Final Report
Operations Audit of Electric and Gas Transmission and Distribution of NorthWestern Energy – Montana

Presented to the:

NorthWestern Energy – Montana

By:

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I. Introduction

A. Scope and Review Process

1. The Company

NorthWestern Corporation provides electricity and natural gas to over 600,000 customers in Montana, South Dakota and Nebraska. The corporation's headquarters are in Sioux Falls, S.D. The electric system has more than 29,000 miles of transmission and distribution lines and associated facilities serving 299 communities and surrounding rural areas covering two-thirds of Montana, eastern South Dakota, and Yellowstone National Park in Wyoming. The natural gas system includes approximately 7,600 miles of transmission and distribution pipelines and storage facilities that serve 172 communities and surrounding rural areas in Montana, South Dakota, and central Nebraska. NorthWestern Energy has approximately 1,300 full-time employees.

NorthWestern entered into an agreement in October 2000 to purchase Montana Power's utility business for $602 million in cash and the assumption of $488 million of existing debt. On January 29, 2002, the Montana Public Service Commission (MPSC) approved NorthWestern's acquisition, and on March 12, 2002, Montana Power became known as NorthWestern Energy (NWE).

NorthWestern Corporation announced on September 15, 2003, that it had filed a voluntary petition for relief seeking to reorganize under Chapter 11 of the United States Bankruptcy Code to facilitate a financial restructuring of the Company. The company also announced that it was in discussions with interested parties regarding the sale of its principal non-utility businesses.

NWE–Montana (NWE–M) makes up a large percentage of the parent corporation. It has electric and gas operations covering over 100,000 square miles, or 73 percent of Montana. It has over 300,000 electric customers and nearly 160,000 gas customers. NWE–M's electric T&D system includes 7,000 miles of transmission and over 16,000 miles of distribution lines. The natural gas T&D system includes nearly 6,000 miles of pipeline.

2. Audit Scope

NWE issued a Request for Proposals (RFP) on March 2, 2004, that indicated the company was interested in an audit of NWE–M's electric and gas transmission and distribution operations. The scope document with the RFP asked for an evaluation of NWE–M's:

- inspection, maintenance, replacement, and upgrading of equipment and overall transmission and distribution system
- system performance compared to other similarly situated utilities, detailing significant differences and similarities in system operation, planning, and design
- collection, analysis, use, and adequacy of system reliability data and indices of NWE's policies/measures used to evaluate system reliability

- work priority guidelines and the sufficiency of the resulting expenditures [toward items identified within those guidelines] both by category and in the aggregate for transmission and distribution operation and maintenance.

The scope document also asked the selected consultant for an opinion as to whether the T&D standards and practices used by NWE–M are best utility standards and practices and the basis of that opinion and the identification of any areas that need improvement and recommendations to improve the situation to the level of best utility practices. Finally, the scope document listed specific items to be included in the audit under the general topics of electric, gas, safety, cost analysis methods, and key financial indicators.

The Liberty Consulting Group (Liberty) responded to the RFP. Liberty explained that a better term for the audit's evaluation standard would be "good utility practices" rather than "best utility practices," as the latter might imply a standard that is not cost-justified in all cases or one that is unnecessary in a particular situation. NWE–M agreed with this interpretation of the evaluation standard. On March 25, 2004, NWE–M notified Liberty that it planned to award the audit to Liberty.

3. The Liberty Consulting Group

Liberty is well qualified to examine service reliability issues, having done so on more than ten occasions for public service commissions and for two major electric distribution utilities. For example, following highly publicized outages in the city of Chicago during the summer of 1999, the Illinois Commerce Commission *(ICC)* retained Liberty to perform a comprehensive investigation of the reliability of Commonwealth Edison's T&D systems. The ICC then retained Liberty to investigate an additional outage that took place and to verify that Commonwealth Edison appropriately implemented the recommendations resulting from the internal and external investigations.

Liberty's team for this audit included senior, experienced personnel in the areas of electric and gas operations, safety, and financial analysis. Among others, Liberty's team included the engagement director for Liberty's prior T&D audits and outage investigations, the former Chief Engineer of the New Hampshire Public Utility Commission, the former owner of a national electrical equipment testing and failure investigation firm, and a former senior utility financial manager.

4. Review Process

Liberty started the audit in early April with orientation meetings and initial interviews with company personnel in Butte, MT. Data gathering and analysis involved written data requests to the company, on-site and telephone interviews, and site visits and inspections. NWE–M responded to over 100 written information requests. Liberty discussed concerns and opinions with all levels of company employees and with a union representative. On May 4, 2004, Liberty briefed the MPSC on the scope and schedule of the audit. Liberty provided a draft report to

NWE–M on June 22, 2004, for the purpose of determining factual accuracy and any matters of confidentiality.

B. Summary of Findings and Recommendations

The RFP for this audit listed four primary areas for evaluation:

- Inspection and maintenance of the T&D systems
- System performance
- Reliability system
- Priority system and resulting expenditures.

Liberty found that while NWE–M's operations were generally consistent with good utility practices, there were weaknesses in implementing electric inspection and maintenance programs. System performance has been reasonable, but there are trends in electric service interruption frequency and number of outages that should be of significant concern. NWE–M's reliability information and reporting system is good. The company's priority system can be very useful in establishing the most cost-effective ways to deploy resources. However, it may cause the company not to accomplish some routine but necessary inspection and preventive maintenance work. Current and planned T&D spending levels may not be sufficient to conduct the necessary inspection and maintenance, prevent a backlog of critical project completion, and continue to provide the expected service quality.

Liberty found that NWE–M operates, plans, and engineers the electric transmission system consistent with good utility practices. However, with regard to transmission system inspection and maintenance, the number of electric transmission system outages caused by defective system hardware and relay scheme problems is a concern. NWE–M's electric transmission system vegetation management practices and plans could adversely affect reliable system operation.

Liberty also found that NWE–M operates and engineers the electric distribution system consistent with good utility practices, but that there are weaknesses in distribution system planning. In electric distribution system inspection and maintenance, Liberty found areas needing improvement with regard to cable failures, protection against animal-caused outages, tree trimming, and compliance with inspection schedules.

In general, Liberty did not have major concerns in the area of gas transmission and distribution. There were several areas including planning, the use of farm taps, and third-party damages in which Liberty made recommendations for improvement.

Liberty found that NWE–M has a strong and thorough safety program and a safety-conscious culture.

Even though this was an audit of the operations of NWE–M's T&D systems, the special financial conditions facing the company are extremely important in determining whether it has and will be able to continue to provide reliable service to its customers. Liberty analyzed historical and projected capital and O&M and concluded that the company should determine the expenditures that will be required to make up for recent cutbacks, correct deficiencies in electric T&D practices, and meet reliability and operational goals. Staffing reductions, particularly engineers and technicians, could also have an adverse effect on the quality of service.

Throughout the course of this audit, NWE–M's personnel were forthright and cooperative with Liberty's consultants. They were timely in responding to information requests and in scheduling interviews and site visits.

The following is a list of recommendations and page references in this report. Liberty also made several suggestions on less important matters that it believes NWE–M should consider to improve its operations.

II. Electric Transmission and Distribution (T&D)

A. T&D Reliability Information System and Results

1. Information System

NWE–M has a very useful and flexible system for recording and computing electric reliability information. The system has the capability to calculate the standard reliability indices for the state, each of the distribution divisions, each distribution system feeder, and in other ways. Anyone in the company can access the database for the purposes of determining performance in unique ways, but only a limited number of people can actually enter or change the recorded information. NWE–M reported that its system is usually up to date within two to four weeks of any outage.

On at least a monthly basis, an engineer in the Butte home office pulls service orders from NWE–M's customer service software and from the outage management system (OMS). The engineer runs a variant report and sends it to the divisions to reconcile all customer-reported outages against those in the OMS. NWE–M counts all outages that affect customers. NWE–M reports reliability indices to the Montana PSC on a quarterly basis and to company management on a monthly basis.

The number of customers affected by an outage, the duration of an outage, and the source and cause of an outage are all determined locally in the divisions and entered into the OMS. It is unclear whether the divisions are determining these factors in a consistent manner. While the occurrence of an outage is reasonably certain in the data, the accuracy of the indices depends on accurate input of the number of customers affected.

NWE–M's calculation of reliability indices is consistent with the IEEE standard on the subject. However, the company has not documented its process. Much to the credit of NWE–M, the company does not attempt to make exclusions for major events such as significant storms.

To identify and prioritize circuits for reliability projects, NWE–M uses in-house software packages to track transmission and distribution circuit reliability indices, the number of outages by cause categories, and defects identified by inspection programs. NWE–M has very detailed lists of outage causes and causes of equipment failures. NWE–M's reliability prioritization methods are consistent with good utility practices.

2. Reliability Results

NWE–M's current target for the standard reliability indices is the prior three-year average. While this form of a target may have an advantage in meeting customers' expectation, it is not a clear goal that personnel can identify with and strive to meet. NWE–M may want to consider establishing specific goals that are demanding but achievable for the service territory and for each of the divisions. Service territory goals such as an average interruption frequency of 1.0 and an average interruption duration of 90 minutes could help personnel focus on improving or maintaining good reliability performance.

NWE participates in several benchmarking surveys including one that measures reliability indices. For the year 2002, NWE–M ranked in the second quartile for system average interruption duration and frequency (SAIDI and SAIFI) and in the third quartile for customer average interruption duration (CAIDI).

Liberty reviewed NWE–M's reported reliability statistics (CAIDI, SAIDI, and SAIFI) for the years 1999-2003 for the state and for each of the six divisions. Liberty also reviewed first quarter results for each of the years 2001-2004.

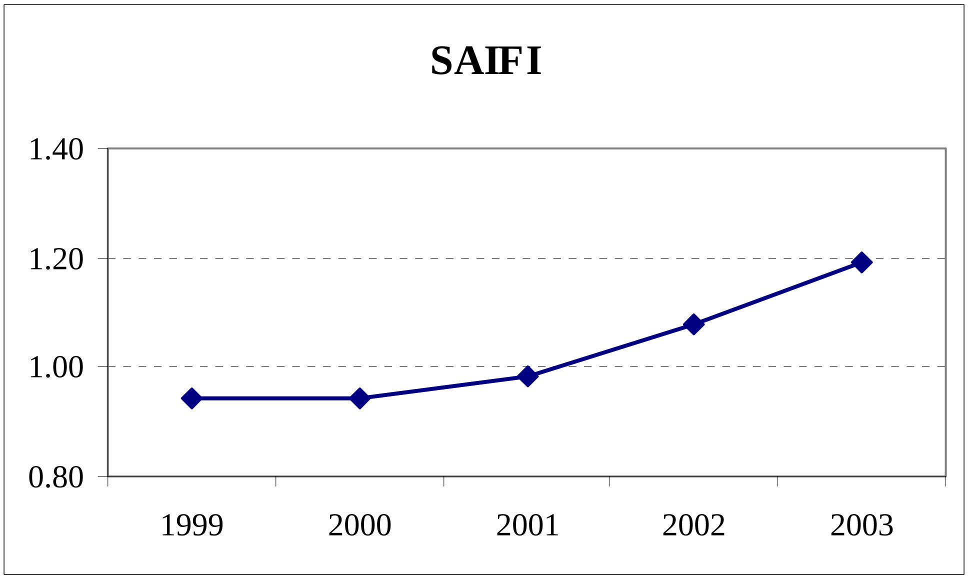
NWE–M has been able to maintain its reported interruption durations (SAIDI and CAIDI) at good levels over the period 1999 through the first quarter of 2004. The system average interruption duration index[1] for 2003 was 104 minutes, which compares to the average for the period 1999-2002 of 96 minutes. One reported average of this index for many utilities for the year 2002 was 95 minutes. The SAIDI reported for the Billings division improved by 30 percent in 2003, while the same index for the Helena division worsened by over 100 percent. The Helena division went from an average duration of 59 minutes for the 1999-2002 period to an average duration of 131 minutes in 2003.

NWE–M said that its 2004 Distribution Field Staffing Plan and Analysis considered the staffing required for it to improve outage response time and reliability at locations remote from division operating centers. This led to placing additional personnel in smaller outlaying communities where response time could be improved.

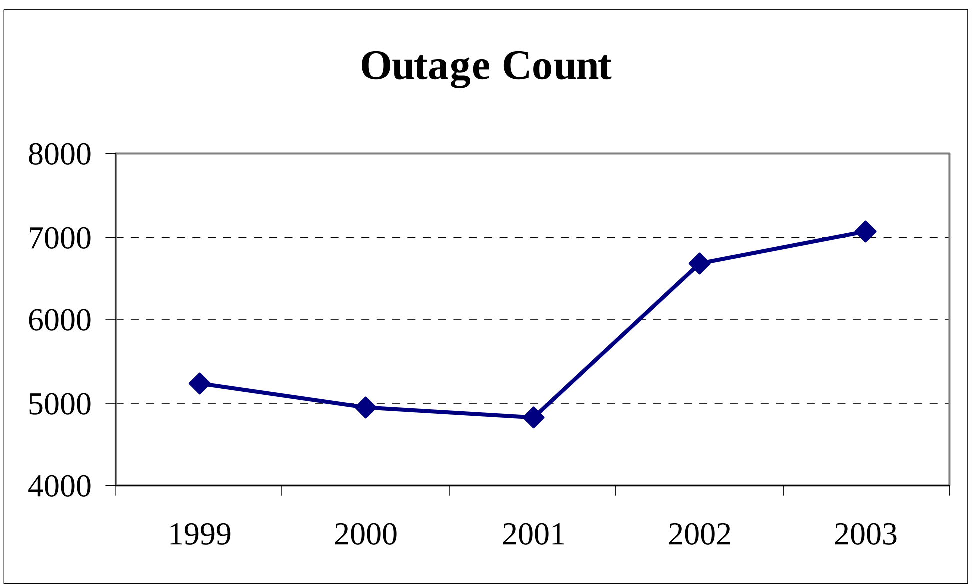
While the frequency of interruptions on NWE–M's system remains in a reasonable range, the trend over the last few years is not good. NWE–M reported a system average interruption frequency index[2] of 1.19 for the year 2003. This compares to a four-year average of 0.99 for NWE–M and an average index for many utilities of 1.2 for the year 2002. However, NWE–M's reported SAIFI increased steadily and saw a 27 percent increase from 1999 through 2003. Among the divisions, Billings reported an improvement in SAIFI for the year 2003, while the frequency index for Helena moved from a four-year average of 0.6 to over 1.3 in year 2003. In the first quarter of 2004 alone, the number of customers that had a service interruption in both the Helena and Missoula divisions was half of the total number of customers in those divisions. For the whole service territory, the frequency index increased in the first quarter of 2004 by 47 percent over the average for the first quarters of the years 2001-2003.

[1] SAIDI: determined by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period.

[2] SAIFI: Determined by dividing the total number of customers interrupted in a time period by the average number of customers served.



Straight counts of outages do not provide information related to the number of customers affected or the duration of interruptions. However, outage counts have the advantage of not being subject to any errors introduced by the methods used to determine those factors. Therefore, outage counts can provide meaningful information with respect to the condition of the T&D system. NWE–M experienced a 30 percent increase in the number of outages in 2003 compared to the average for the period 1999-2002.



Outage counts went up in all divisions in 2003, with Bozeman and Helena seeing a 66 percent and 47 percent increase, respectively. The outage count for the state in the first quarter of 2004 increased by 24 percent over the average first quarter experience in 2001-2003.

It is common that when utilities begin collecting reliability data on a more consistent basis, indices tend to look worse because of better reporting, not worse because of actual performance. However, the recent increases in outage counts and SAIFI, coupled with incomplete maintenance and inspection efforts and the age of the system, should be of concern. Reliability indices tend to be lagging indicators compared to actions taken or actions not taken that can affect system reliability. That is, reliability improvement projects or the failure to conduct good preventive maintenance do not show up in the indices for some period of time. For this reason, NWE–M should address the increasing trend of its interruption frequency and outage count. These trends could be the result of NWE–M's practices over the last several years, and it may be difficult to reverse such trends in a short period.

For the years 2002 and 2003, equipment failure was the most common cause of outages that NWE–M reported. The average of those two years (1,747 outages) increased by 32 percent over the average for the prior three years (1,325 outages). This trend could be an indicator of deteriorating system conditions.

3. Use of Reliability Information

The flexibility, ease of use, and widespread access to NWE–M's reliability database are impressive. However, the system is relatively new, and NWE–M can continue to improve the uses of the information available from the system. For example, with appropriate feedback from the field, in the future NWE–M should be able to better use the system in making decisions regarding the effect on reliability of making certain changes or implementing certain projects.

4. Findings and Recommendations

Liberty has one recommendation and two suggestions for improvement related to NWE–M's reliability information system.

Recommendation II-1: Analysis of Interruption Frequency

Because of the recent increasing trends in interruption frequency and outage counts, NWE–M should study the cause factors and perform an analysis of the measures. NWE–M should pay particular attention to interruptions caused by equipment failures. It should then specify the corrective actions it plans to take to improve performance. In addition, NWE–M should monitor closely the interruption duration indices to determine whether they too are on the rise.

Liberty's suggestions for improvement are:

- NWE–M should examine the accuracy and consistency among the divisions of data received concerning the number of customers affected and the duration of service interruptions. Liberty did not test this accuracy during its audit. However, Liberty did note differences in the ways the divisions handled other matters. Therefore, without centralized guidance, it is likely that the divisions determine these factors in different ways, possibly with errors that could significantly affect results.

- NWE–M should continue to improve the usefulness of its reliability information system. This requires accurate data input and feedback from the divisions concerning the implementation of fixes and projects. NWE–M should aim to be able to make cost-benefit decisions on the basis of projected improvements in reliability indices.

In addition, the following suggestion applies across all aspects of NWE–M's operations. Liberty provides this suggestion below and does not repeat it in other sections of this report on T&D operations.

- NWE–M does not consistently or formally document many of its processes and programs. This creates the risk of missed or inconsistent application of the appropriate actions desired by corporate management, particularly when manager and engineer personnel change. Liberty suggests that NWE–M assign a corporate document control manager, that its documentation program indicate how it establishes processes and programs, and that all documents include implementation dates, revision numbers, and signed authorizations.

B. Transmission System

NWE–M's transmission system sends power from in-state generation sources to NWE–M's distribution points and to other, non-affiliated transmission systems. The system consists of approximately 7,000 miles of transmission lines, 270 circuit segments, and 125,000 transmission poles with associated transformation and terminal facilities. Most of the transmission system is overhead lines; NME–M owns three miles of underground line at 69 kV. The following table shows the line-miles of the various voltages in the transmission system.

Voltage	Line-Miles
500 kV	495
230 kV	953
161 kV	1,118
115 kV and below	4,159

Liberty reviewed NWE–M's organizations, processes, and funding to determine if the transmission system is providing and will likely continue to provide reliable service. Liberty conducted interviews and requested information to determine whether NWE–M was operating, planning, and reinforcing its transmission system to prevent exceeding equipment ratings under both system normal and probable abnormal situations, and whether it was inspecting and maintaining its electric transmission equipment so as to provide reliable service.

1. Operations, Engineering, and Planning

a. Introduction

An electric transmission system should be planned, operated, engineered, monitored, reinforced for growth, and upgraded for improved effectiveness such that no component is loaded in excess of ratings and that no unstable conditions are created that might result in cascading blackouts. Proper transmission system planning includes monitoring peak loads, forecasting future loads, performing studies, issuing specific operating instructions when component loading or system stability might be jeopardized, and proposing projects to alleviate possible loading or stability problems caused by future load growth. Proper system operations include monitoring transmission system conditions, safely restoring equipment after outages, controlling transmission switching, and preparing for and reacting to abnormal conditions such as storms and fire. Proper transmission protection system operation and planning includes performing fault current studies, verifying proper relay scheme operations, planning and installing upgrade relay schemes where older schemes are not effective or dependable, and investigating relay scheme misoperations. Proper transmission line and substation engineering requires that all transmission line and substation equipment and systems are specified, designed, and constructed to assure compliance to the National Electric Safety Code (NESC) and to provide reliable and effective operation consistent with the planners’ expectations.

b. Evaluation and Analysis

NWE–M serves about 300,000 Montana electric customers across about 100,000 square miles in rural areas and in about 191 small and medium sized communities. It supplied 1,442 MW to its Montana customers and wheeled 294 MW through the state on its greatest peak-load day—an extremely hot day in July 2003.

NWE–M’s transmission System Operations Control Center (SOCC) in the Butte area controls the entire electric transmission system using a nearly complete SCADA (system control and data acquisition) system and division distribution field personnel. SOCC personnel work with NWE–M’s transmission planning engineers, and comply with NERC planning guidelines, to assure that they operate the transmission system in ways to prevent overloaded and unstable conditions during transmission maintenance outages and abnormal system conditions. SOCC operators have written procedures based on NERC requirements to reduce load if an unexpected event occurs to preserve system stability. NWE–M provides 48 months of training to apprentice operators. NWE–M certified some of the operators in the procedures to safely bring generation back on line after a blackout (black start). Some of the electric system operators are cross-trained to control NWE–M’s gas transmission system. Although NWE–M does not presently drill and evaluate fully qualified SOCC operators on the practice of large and multiple outage events, System Operations has a simulator (DTS – Dispatcher Training Simulator) that it uses for training new operators. NWE–M said that it will be using this system simulator to drill its operators in large and multiple outage events as part of its continuing emergency outage education training required by NERC.

NWE–M extends the SCADA system to a backup operating center in Butte and, in the event that the SOCC becomes uninhabitable, NWE–M can use this backup facility to monitor and control the transmission system.

The SOCC monitors weather using an Internet service. It presently does not monitor lightning activity, but NWE–M indicated that it plans to do so using programs for monitoring both real-time and historic lightning activity. This will help prepare operators during storms and will help relay engineers identify outages caused by lightning.

NWE–M's transmission system has sufficient transfer capacity to serve its Montana customers into the foreseeable future. The Montana transmission system includes NWE–M's transmission lines at 230 kV and below, and the 500 kV transmission system owned by the Colstrip participants (and operated by NWE–M). Most of the time, the transmission system is exporting power through its lines that connect to other entities. For example, NWE–M's 2003 system peak load was about 1,700 MW and total generation (considering all sources) in Montana is about 4,000 MW. The three existing transmission system paths that interface with other utilities' transmission systems have a combined export capability of about 3000 MW. NWE–M will have to modify some or all of these paths to accommodate substantial new generation development in Montana. Transmission planners now monitor transmission bus voltage, transmission and substation bus loads, power-factor, and line losses using its System Watch studies with data collected from SCADA and its Energy Management System, and PI-DataLink software. From its load studies, planners verify the accuracy of previous forecasts, prepare new forecasts, reaffirm or identify long-term system reinforcement needs, prepare operating instructions to transmission operations for maintenance outages, and identify loading and stability problems caused by proposed generation connects to the system. Transmission planners forecast peak loads and identify system growth and stability reinforcement needs for up to 10 years in advance. NWE–M develops peak load forecasts based primarily on linear regression models that use 14-year historical data and maximum and minimum temperatures (for summer peak and winter peak) patterns. Transmission planners perform the load and stability studies required by WECC/NERC guidelines. Liberty reviewed NWE–M's 2003 transformer loading reports and found that except for a couple of small substation transformers, NWE–M's substation transformers were loaded at peak conditions well below manufacturer's ratings, even though the 2003 summer peak temperature was extraordinary elevated.

NWE–M's planning reported that it has a couple of areas where the company will reinforce the transmission system over the next few years. Planning indicated that, on the basis of planned load growth and generation connects and the completion of these reinforcement projects, the NWE–M transmission system should not have loading or stability problems during the next ten years.

NWE–M rates its overhead transmission lines based on ambient air temperature of 25°C (77°F), 50°C rise, conductor temperature of 75°C (167°F), and a 2 foot/second (1.4 mph) wind. It rates its underground transmission cables based on the manufacturer's ampacity for the buried cable considering the depth, phase placement, and type of backfill. It rates other equipment per manufacturer's ratings. NWE–M allows transformers to operate up 100 percent of manufacturer's rating during the summer, and up to 125 percent in the winter. There are no formal emergency ratings.

Transmission system engineers prepare line and substation designs, and issue transmission reinforcement and upgrade capital projects using NWE–M standards, and order equipment in accordance with its specifications. They also issue and prioritize transmission line and substation maintenance and reliability programs. Transmission engineers initiate and track transmission growth reinforcement and upgrade work, but division distribution crews managed by division distribution engineers perform the actual work (except for relay and control work). Division management acknowledged responsibility for accomplishing much of the transmission line and substation reinforcement and upgrade work; Liberty did not find any examples of deficiencies in this work. However, with the present level of division distribution work loads, using division crews to do the electric transmission line and substation growth and upgrade work might be reducing the availability of division crews to properly address division distribution work. Using the divisions to complete transmission work might also delay completion of transmission line and substation work. Also, Liberty found that the centralized transmission line engineers cannot spend much time in the field, except to sometimes verify completion of growth and upgrade work. Division engineers field-manage most transmission and substation work. However, most of divisions may not be sufficiently staffed with engineers to assure that electric transmission line and substation growth and upgrade projects are executed in the most effective and timely manner.

The centrally located transmission protection engineers perform fault and relay coordination studies and prepare relay settings to meet equipment protection and the planners' stability requirements. They prepare relay and control scheme designs for substation reinforcement and upgrade projects, manage the relay maintenance program, investigate transmission relay operations and identify relay scheme misoperations for further investigation and correction, and work with relay technicians at the Butte relay shop and in the divisions. Relay shop technicians manufacture and wire control panels and cubicles. These relay technicians, and a few other relay technicians located in the divisions, perform relay maintenance.

NWE–M allows its management and engineers to be flexible and to work out problems together, without necessarily following a chain-of-command. At other utilities, Liberty found that management and engineering groups tend to close ranks and not communicate with other groups, often not knowing what other groups are doing nor willing to assist other groups. This practice can lead to lack of questioning poor processes, inefficiencies, and lack of knowledge transfer. However, Liberty found that managers and engineers at NWE–M openly communicate. Engineers can be innovative. Liberty observed that NWE–M's management and engineers seem to be knowledgeable about their own responsibilities and what other groups are doing.

There are approximately 698 transmission relay schemes on the NWE–M transmission system. Of these, modern, reliable programmable relays primarily make up 224 or 33.5 percent. Although relay engineering tracks relay schemes using paper setting sheets and maintenance reports, they do not have an electronic relay database nor track how much electro-mechanical relay settings have drifted during the time between maintenance periods.

NWE–M uses microwave and fiber optic relay communication systems. It was a pioneer in the use of fiber optics for communication relay trip and block signals among its protection schemes.

c. Findings and Recommendations

Liberty found that NWE–M operates, plans, and engineers the electric transmission system consistent with good utility practices. Liberty has no major recommendations in this area. However, Liberty does have some suggestions that NWE–M should consider for improvement.

- Liberty suggests that NWE–M carry out its plans to periodically conduct drills for its electric transmission operators with large-scale and multiple emergencies to verify that its procedures are effective and that the operators are adequately trained and skillful to effectively minimize outages and unstable conditions during possible but unlikely multiple storm, fire, and terrorist-caused events.

- NWE–M should perform a study of the likelihood and consequences of a complete failure of the SOCC.

- Liberty suggests that the centralized transmission engineering group assume full responsibility for preparing and field-managing transmission line work to allow division engineers to concentrate on distribution responsibilities. This would likely require additional staffing of engineers and technicians for the transmission group.

- NWE–M has only one substation engineer, and a transmission line engineer who sometimes assists. This one engineer is not only responsible for a fairly large number of substation projects, but also for managing the transmission equipment preventive maintenance program. It is likely that this one substation engineer does not have the time to thoroughly prepare and field-manage substation projects, and must depend on division distribution engineers to perform some of these functions. Liberty suggests that the transmission engineering group assume full responsibility for substation work to allow division engineers to concentrate on distribution work, and to provide better assurance that substation projects are prepared, managed, and executed properly. This would likely require additional staffing of engineers and technicians for the transmission group.

- NWE–M bases its equipment load ratings on standard ambient conditions; it does not assign emergency ratings to transmission and substation equipment. The lack of a dynamic ratings program and the lack of emergency ratings have not caused problems because the transmission equipment typically has excess capacity. However, situations (*e.g.*, loss of a transformer or line during a maintenance outage, or unexpected multiple equipment failures) may arise in which operations may need to quickly identify how much continuous loading is allowed at specific ambient conditions (*i.e.*, ambient temperature, wind speed) without causing excessive equipment thermal aging, and how much emergency overloading is allowed for different amounts of time necessary for switching or connection of portable substations. Liberty suggests that NWE–M planning or engineering develop for themselves and operations a dynamic rating system, determine acceptable loss of equipment life caused by overloading, and identify acceptable overload conditions. The assignment of ratings should be the responsibility of one ratings engineer, but it should involve all affected groups, including distribution engineering and planning, to be consistent across the company. NWE–M should formally review ratings when system conditions change and when it installs new equipment.

- Transmission planners do not take into account electro-mechanical relay setting drift (change in settings between maintenance periods) in their studies. Relay engineers do not analyze which relays drift excessively, how much they drift, how many drift, and at which substations they drift excessively. Drift information is not readily available to relay engineers; relay maintenance reports are not in an electronic format to allow ready access to these data. Liberty suggests that planners determine how much relay setting drift system stability studies allow and relay engineers do the same in their coordination studies.

- The SOCC monitors weather on the Internet. The divisions do not monitor weather. Liberty suggests that NWE–M consider some means for the SOCC to notify divisions when extreme weather is approaching a division's territory.

2. Inspection, Reliability, and Maintenance Programs

a. Introduction

A utility should inspect and maintain the transmission system to satisfy the NESC and NERC/WECC requirements and to provide reliable service to transmission customers and to the distribution system. A utility should design inspection programs to identify defects that, if left un-repaired, might result in risk to safety, equipment, and reliability. Preventive maintenance helps assure reliable and safe equipment operation. For example, utilities should lubricate and exercise circuit breaker mechanism about every five years to prevent seizing. Moisture or carbon contamination in circuit breakers or transformer oil will reduce dielectric strength and might cause catastrophic failures. Designing logical and thorough inspection and maintenance programs, and compliance to those programs, are important to safe and reliable transmission system operation.

b. Evaluation and Analysis

About 2,800 miles of NWE–M's 7,000 miles of transmission line passes through treed or forested areas. There are 68 transmission substations and about 70 interconnection terminals with other utilities, including about 60 interconnections with electric cooperatives. Transmission lines to some of the other utilities are radial fed, making maintenance more difficult (requiring hot line work) and more critical (the only power feed). Some of the connected loads are so small that loop feeds likely are not cost-justified. Much of the transmission equipment is aged (*e.g.*, only about 14 percent of the transmission lines are less than 20 years old and 22.4 percent are over 80 years old). Some transformers have been in service since the 1910s and some oil circuit breakers since the 1930s. The steel structures on one 100 kV line were installed in 1907.[3] Only about 30 percent of the system's lines and substation transformers are less than 20 years old.

Equipment age alone is not a good indicator of functionality or reliability. Some aged equipment may last a very long time if the utility maintains it well and does not operate it in excess of ratings. A good inspection and testing program will help determine when equipment costs more to maintain in a reliable condition than replacement. Liberty examined a few substations and a short section of an old transmission line (to the Yellowstone cooperative). Liberty found the substations (one or two in each the Billings, Bozeman, Butte, Helena, and Great Falls divisions) clean and free of major condition concerns. The physical condition was better than some substations inspected by Liberty at other utilities. The transmission line poles examined were cedar; they may retain adequate strength for 100 years or more, even though the exterior of some of the poles appear to be in poor condition. It is important, however, that NWE–M inspect these aged poles periodically for major fungal and animal damage, treat with a fumigant, and replace when pole strength is questionable. Liberty did not observe any trees in contact with transmission lines. However, Liberty did not have the opportunity to perform a thorough inspection of transmission lines in forested areas.

NWE–M experienced 754 momentary (less than two minutes duration) outages and 374 sustained outages on the transmission system during 2003. NWE–M identified the causes of these outages as shown in the table below.

	Percentage of total outages		
Cause	**Momentary**	**Sustained**	**Total**
Animal	0.0	1.1	0.4
Customer-caused	0.5	0.8	0.6
Terminal equipment	0.8	5.6	2.4
Foreign	0.3	0.3	2.4
Hardware problems	19.4	36.6	25.1
Lightning	6.1	1.6	4.6
System protection	4.6	12.3	7.2
Raptor or bird	3.2	1.3	2.6
Tree	3.6	9.1	5.4
Unknown	36.2	12.6	28.4
Accidents/vandalism	1.7	6.4	3.3
Weather	23.6	12.3	19.9

Only four cause-types caused 70 percent of the sustained transmission outage: hardware 37 percent, system protection 12 percent, weather 12 percent, and trees 9 percent. NWE–M provided the following classification of the hardware problems that caused sustained outages.

[3] However, NWE–M tested a tower to destruction when it recently re-conductored this line.

Air break switches	1.5 %
Conductor	11.7 %
Distribution underbuild	2.9 %
Floater	7.3 %
Insulator	13.1 %
Jumper	0.7 %
Pole/Structure	24.8 %
Static wire	5.1 %
Unknown	23.4 %
Cross arm	9.5 %

Defective poles, cross arms, insulators, and floating conductors accounted for over half of the known hardware-caused outages.

NWE–M's annual inspection programs specify the company's transmission maintenance requirements. These programs include performing annual aerial or ground inspections of the entire system for obvious hazards on the lines, poles, structures, and equipment including vegetation management needs, and detailed ground inspections of lines and poles on 10 percent of the system. The detailed ground inspections include photographing each pole and structure and identifying locations by GPS. The ground line inspections include testing pole integrity and treating all poles to extend pole life. The detailed ground inspection procedure is very inclusive. It includes identify and prioritizing pole and cross arm conditions, right-of-way encroachments, tree clearances and other vegetation problems, line clearance problems, conductor and shield wire defects, pole hardware and insulator defects, ground wire integrity and measuring ground resistance, and guy defects. The procedure should include verifying that guy guards and ground wire moldings are in place at the required locations specified by the NESC.

NWE–M reported that it performed most of the annual aerial and ground inspection and very little of the detailed inspection work in 2003, but fully funded these programs for 2004.

NWE–M assigns transmission maintenance work by order of priority. Immediate hazards to the public or property have highest priority, followed by repairs to avoid an outage, then those that crews should repair when they are in the area. NWE–M rates poles and cross arms 1 through 4. Poles and cross arms rated as 4 have minimal strength and require replacement. Poles and cross arms are rated a 4 (bad) by inspectors are re-inspected by supervisors to verify proper classification. NWE–M gives circuit segments with 4 rating poles and cross arms the highest priority in the transmission system integrity program. There is no specific amount of time that a 4-rated pole or cross arm is allowed to remain in service. NWE–M reported that it has 957 known 4-rated poles on its transmission systems (out a total of about 125,000 poles). NWE–M reported that it has not been tracking the number of transmission poles replaced annually. However, it spent over $2.7 million in 2002, and over $1.7 million in 2003 on system integrity projects that primarily included system integrity pole replacement. NWE–M said that it recognized the need to track transmission pole replacements in its critical system integrity program, and is doing so in 2004.

As stated above, NWE–M includes bad poles and cross arms and repairs to avoid outages in the System Integrity Program for further analysis. The transmission system integrity engineer first evaluates and places a score number on each line segment on the basis of the past year's reliability indices, cause of outages, and line segment criticality to identify and prioritize the worst performing line segments. Through this process, NWE–M identifies line segments for integrity program repairs. The number of line segments included in a year's integrity work is limited by the capital funding made available. The divisions perform Transmission System Integrity work using capital funds allotted by Transmission Engineering. Although Transmission Engineering cannot fully track the completion of transmission integrity work performed by the divisions, the company plans to integrate the transmission and distribution integrity programs and be able to track work completion more conveniently.

The inspections tabulate all other repair work except vegetation management and provide lists to the divisions to work as maintenance tasks within the transmission O&M budgets. Each division tracks the completion of transmission maintenance work in different ways, and Transmission Engineering monitors work completion only on a limited basis.

Transmission Engineering analyzes and prioritizes vegetation clearance problems noted by one of the inspections or from outage data. Considerations given to clearance problems include danger trees (unstable trees that could fall and reach a conductor), trees within the NESC limits, and those that it must trim to meet forested land or NERC/WECC requirements. Engineering prioritizes clearance problems as hazard to public or property, trimming to avoid an outage (hot spot trimming by division crews), trim when in the area, and budget for programmed trimming (by tree trimming contractor). They perform prioritization by a line segment score system. NWE–M currently performs some limited transmission line tree trimming on a regular cyclic basis. NWE–M estimated that, out the 2,800 miles of line exposed to trees, it program-trimmed 108 miles of line in 2002 and 48 miles of line in 2003; and will program-trim 206 miles of line in 2004.

To protect large birds and reduce the number of outages caused by contact of these birds with conductors, NWE–M instituted a raptor program. Whenever utility personnel observe raptors nesting on transmission poles or structures and there have been reliability problems on the circuit, NWE–M builds nesting platforms away from the conductors, or takes other actions, to mitigate the possibility bird-to-wire contact.

Division substation personnel perform monthly substation and periodic battery inspections. They also perform annual infrared inspections on substation connections. Transformer shop personnel take transformer oil samples for dissolved gas analysis and oil quality. Each division's integrity foreman reviews the inspection and infrared reports and prioritizes defects identified. The division is responsible for the tracking and completion of substation defects identified by inspections. Division engineers may become involved with assessments and the corporate substation engineer or the transformer shop foreman (engineer) may become involved. NWE–M does not have a formal policy on how to prioritize and track the defects from substation inspections.

The substation equipment preventive maintenance engineer maintains a tabulation of substation equipment and preventive maintenance history. Although there is no formal substation preventive maintenance program or schedule, the engineer identifies substation preventive maintenance needs. NWE–M has adequate equipment inspection and maintenance checklists and forms. NWE–M allocated some funds for oil circuit breaker preventive maintenance work for 2004. The company services and time-travel tests circuit breakers; it sometimes performs power-factor tests. It does not measure circuit breaker contact resistance.

NWE–M performs much of its own substation and distribution equipment repairs at its fully equipped equipment repair facility (transformer shop) in Butte. The transformer shop provides equipment testing and repair personnel to assist division personnel in performing on-site testing, maintenance, and repairs. The shop also retains a large inventory of spare distribution and substation equipment, as well as a number of portable substations.

The company's program calls for transmission relay performance, timing, and accuracy tests on a 2-, 4-, or 6-year schedule, depending on line voltage. It also calls for testing of station batteries on a 7- or 10-year schedule. However, NWE–M reported that it did not perform periodic relay maintenance in 2003. NWE–M also reported that it has not funded relay upgrade projects scheduled for 2002.

NWE–M reported that it spent the amounts shown in the table below for transmission maintenance in 2001 through 2003. The 2004 amounts are budgeted funds.

Year	Transmission Integrity Capital Funds ($)	Transmission Maintenance O&M Funds ($)	Transmission Tree Trimming Funds ($)
2001	10,272,908	5,621,901	1,036,710
2002	9,311,192	4,233,096	950,814
2003	8,821,164	4,094,271	473,070
2004	13,186,470	5,177,166	919,145

NWE–M funds its transmission system programs on the basis of its work priority system that has nine priority levels. The first four priorities are those necessary to do business—emergency response, outage restoration, hot-spot tree trimming, government required work, and new business. Capital priority level 5 work includes the critical system integrity work; inspections and routine maintenance are capital priority level 8. NWE–M reported that when funds are limited, it completes only some of the capital priority 5 work at that time. NWE–M reported that it has encountered funding limitations that restrict its ability to get capital priority 6 through 9 work performed in any single year. However, it has increased the priority of some lower priority work when warranted.

c. Findings and Recommendations

Liberty found that NWE–M's transmission line and substation inspection and maintenance, and reliability programs are only partially consistent with good utility practice. The following paragraphs provide recommendations to address processes that Liberty believes are not consistent with good utility practices.

Recommendation II-2: Equipment-Failure Outages

The number and percentage (more than 36 percent of sustained outages) of transmission outages caused by defective hardware in 2003, especially poles, cross arms, insulators, and floating conductors is a concern. Because these are primary items identified by the NWE–M's inspection programs and corrected by the system integrity program, either the inspections, or the work to correct these problems, or both, should be intensified. NWE–M reduced the funds spent on these programs in 2003. Liberty found the transmission line inspection programs generally in compliance to NESC and good utility practice, but not NWE–M's adherence to its programs. Budget restraints and the work priority system that puts inspections and maintenance into a low level priority category apparently caused this lack of adherence. Liberty recommends that NWE–M fully fund its inspection, integrity, and maintenance programs and determine what "catch-up" work it should perform because of non-adherence in the past. Considering the age of NWE–M's equipment, Liberty recommends full program compliance.

Recommendation II-3: Transmission Tree Trimming

Trees accounted for over 9 percent of the sustained transmission system outages in 2003. NWE–M reduced funding for tree trimming in 2003. During 2002, 2003, and 2004 NWE–M will have program-trimmed only 13 percent of its transmission system exposed to trees. Other utilities have determined that all lines exposed to trees must be program-trimmed at least every 4 to 5 years. Whenever a utility reduces tree trimming efforts, it requires more time and funds in the future to minimize reliability problems caused by trees. One rule-of-thumb says that $1 saved on tree trimming this year will cost an additional $1.25 the next year. Liberty recommends that NWE–M put its transmission lines on a time-based tree trimming cycle, based on tree types, terrain, and voltage, supplemented by an annual inspection program to identify hot spots. The appropriate NWE–M tree-trimming cycle would depend largely on specific tree growth rates in Montana.

Recommendation II-4: Relay Maintenance

Relay scheme problems accounted for over 12 percent of sustained transmission outages. This is a concern. Although NWE–M has a good relay maintenance program, it has not fully complied with the program nor has it completed relay upgrade projects. Liberty recommends that NWE–M bring its relay maintenance work current and re-evaluate the need to complete the previously scheduled relay upgrade work.

Recommendation II-5: Substation Maintenance

Although NWE–M funded some substation equipment preventive maintenance, it has no formal substation equipment preventive maintenance program. The only preventive maintenance work performed on a schedule is transformer oil sampling and infrared inspections. This is not consistent with good utility practices. Liberty recommends that NWE–M develop formalized substation equipment maintenance and testing programs that include the work it will perform and work schedules based on system priorities, such as equipment voltage and where the equipment is on the system.

Recommendation II-6: Transmission Pole Maintenance

NWE–M transmission pole inspection programs include identifying bad (4-rated) poles. It has not, however, indicated a 4-rated pole replacement timetable in the programs. It has 957 known 4-rated transmission poles on its system. NWE–M was not able to report the number of 4-rated transmission poles replaced in 2002 and 2003, but it said that it is now tracking pole replacements in its critical system integrity program. NWE–M uses 4-rated pole data to prioritize circuit segments included in annual critical integrity programs. However, some 4-rated poles may not be on high priority circuit segments, and therefore NWE–M will not replace them on a timely basis consistent with good utility practice. Because bad poles can have safety concerns, Liberty recommends that NWE–M develop methods for identifying schedules for replacing these poles based on safety concerns as well as criticality, and to replace bad poles based on these determinations even when they are not included in system integrity projects. Liberty also suggests that the transmission pole rating system be common with the distribution system which has 5 rating levels.

Recommendation II-7: Inspection Program Compliance

NWE–M did not fully comply with the schedules set forth its transmission system inspection programs in 2003 Liberty found this not to be consistent with good utility practice. Liberty suspects that transmission was not in compliance with its inspection program schedules for 2001 and 2002, since distribution was performing at only about one-half their rates in those years. Liberty recommends that NWE–M give its electric transmission inspection programs the same funding priority as it does its critical system integrity programs.

Liberty also provides the following suggestions for NWE–M's consideration for improvement.

- NWE–M does not include the verification of pole ground wire moldings, and guy wire guards and markers, at the locations described in the NESC, in its transmission pole programs. Liberty found that excluding these items in the inspection programs not to be consistent with good utility practice. Liberty suggests that NWE–M include these items in its transmission pole inspections and consider having inspectors install guy markers, guy guards, and ground wire moldings, as appropriate.

- NWE–M's oil circuit breaker preventive maintenance check list does not include contact resistance tests. Measurement of contact resistance is an important test to identify potential breaker problems.

- NWE–M reported that it plans to fully track its transmission integrity work after it transfers transmission data to the Critical System Integrity software that distribution engineering is developing. This software program will allow the divisions to conveniently report when it completes transmission integrity work. Transmission Engineering does not track the less critical transmission maintenance work that is not included in the integrity program. The divisions use different methods of tracking this work. Liberty suggests that NWE–M proceed with centralized tracking of transmission critical integrity work, including tracking pole replacements, and develop a tracking method for minor maintenance work identified and performed in the divisions. Tracking of completed integrity work will help Transmission Engineering and the divisions determine how effectively the integrity work is improving transmission reliability indices. Tracking of minor maintenance tasks completed should also help to identify funding needs for the divisions.

- Transmission Engineering does not track substation defects and repairs. In order to better identify substation corrective maintenance budgeting needs, Liberty suggests that NWE–M develop a method for tracking substation defects identified and the corrective actions taken.

- NWE–M has only one substation design engineer. This person has little time to be a substation equipment maintenance specialist. The divisions generally refer substation equipment technical problems to the transformer shop foreman. Although the transformer shop foreman is very knowledgeable, he should not be the only equipment expert in the company. Liberty suggests that NWE–M staff a position of corporate substation maintenance engineer to provide full time technical management of the substation inspection and repair and preventive maintenance programs. This engineer could also function as the primary substation equipment specialist.

C. Distribution System

Power flows from NWE–M's transmission system to 291 distribution substations, then to 671 distribution circuits (at 4 kV, 12 kV, and 25 kV), and finally to the pole-mounted or pad-mounted transformers that provide service its customers. The distribution system contains almost 15,000 miles of overhead distribution lines, about 350,000 poles, and about 2,500 miles of underground distribution cable.

Liberty reviewed NWE–M's organizations, processes, and funding to determine if the distribution system is providing and will likely continue to provide reliable service. Liberty conducted interviews and requested information to determine whether NWE–M was operating, planning, and reinforcing its distribution system to prevent exceeding equipment ratings under both system normal and probable abnormal situations, and whether it was inspecting and maintaining its electric distribution equipment so as to provide reliable service.

1. Operations, Engineering, and Planning

a. Introduction

An electric distribution system should be planned, operated, engineered, monitored, reinforced for growth, and upgraded for improved effectiveness such that no component is loaded in excess of ratings and that customers are not exposed to excessively low voltages. Proper distribution system planning includes monitoring peak feeder loads, forecasting future loads, performing loading and voltage studies, and proposing projects to alleviate possible loading or voltage problems caused by future load growth. Proper system operations include monitoring distribution system conditions, quickly initiating response to customer outages, and preparing for and reacting to abnormal conditions such as storms and fire. Proper distribution engineering includes specification, design, and construction of distribution equipment to assure compliance to the National Electric Safety Code (NESC) and to provide reliable and effective operation consistent with the planners' expectations.

b. Evaluation and Analyses

NWE–M has reduced its division management and engineering staffing by about one-third since 1999. However, the way that division staff personnel take on multiple responsibilities is impressive. Equally impressive is the way that some divisions promote innovation (*e.g.*, using relays to obtain peak loads for Billings planning). The Butte division, which has only two non-supervising engineers, had no manager and no foreman. These engineers had responsibilities for division gas and electric design, integrity, maintenance, and planning. They were also supervising crews. In addition, they volunteer to be on call much of the time. Fortunately, the corporate distribution engineers in Butte have also agreed to be on call at times. In general, Liberty found NWE–M's personnel to be dedicated and cooperative.

Liberty observed that NWE–M's field crews appear to be putting in a full day's work. This is unlike observations at some other utilities. Many of NWE–M's linemen are in their 50s and some say that they are not interested in working many hours of overtime. They complained that the company did not have sufficient apprentices. However, crews respond to emergencies. For example, while Liberty was on site, crews from Great Falls and other divisions responded very quickly and worked in extremely poor weather conditions to restore services during and after a spring snow storm that broke 11 transmission poles and about 140 distribution poles. The company indicated that this storm was the worst emergency for the Great Falls division since 1982.

NWE–M had about 27 in-house crews and 15 contract crews working when Liberty was on site. NWE–M's policy is to have its peak field workforce made up of about 60 percent in-house and 40 percent contractor. It uses contractors primarily for growth and public improvement work. Being able to use contract crews to work when needed is an advantage many utilities do not have. NWE–M made a field crew staffing study to evaluate the crew staffing needs and is currently implementing that plan.

NWE–M has not recently conducted a home office and division support staffing study. It appears that the minimal staff of engineers in some divisions is causing difficulties in the timely completion of work. Line crews complain that line project drawings and instructions are not always accurate and that engineers have no time to work with crews on the job. NWE–M says that it requires four to six weeks to connect a new customer. Many utilities average about 10 days for this work. Engineering backlogs may contribute to the extending connect time.

The six divisions supply all field personnel for transmission and distribution work. NWE–M centrally authorizes growth and integrity capital projects and prioritizes them using the guidelines discussed above in the transmission section of this report. Division supervision manages all work; NWE–M does not have a centralized work management group; division supervision plans and schedules all work. Crews perform maintenance work under standing or blanket orders, which allows the freedom for the divisions to perform maintenance repairs without spending time and expense of tracking each repair project. However, the use of standing orders complicates tracking of maintenance work. NWE–M is considering the implementation of activity-based blanket accounts to allow some tracking of maintenance work by work type, without being unnecessarily restrictive.

NWE–M’s six operating divisions control the distribution system. There is no centralized distribution control center. The divisions plan, schedule, and dispatch all work. NWE–M’s call center in Butte passes outage reports to division dispatching personnel during regular hours. A dispatcher is also on duty during second shift at the call center to take customer calls, and a phone operator is on duty to take third-shift calls. On-call division supervision and engineering personnel take the after-hours calls and dispatch field personnel. This system works only due to the dedication and cooperation of the division supervisors and engineers. At some divisions, NWE–M has a slow crew call-out process because the company is contractually required to attempt to equalize field personnel overtime.

NWE–M does not have an automatic outage management system (OMS), a centralized distribution control center, or a complete distribution SCADA system. Dispatchers cannot control any of its distribution circuit breakers remotely. Field personnel must travel to substations to perform switching and to record load and voltage indications. Although SOCC operations can monitor substation transformer loads, NWE–M does not have SCADA equipment installed on the distribution feeders; in some cases there are no panel ammeters. However, distribution planners have adequately monitored the need for growth projects using manual data gathering. The Billings and Bozeman divisions, where growth is much greater than in the other divisions, have been replacing many of its electro-mechanical feeder breaker relays with programmable relays that allow the division’s engineers to monitor load on many of the feeders. Engineers at the Billings division are able to automatically download nearly all the division’s daily peak feeder loads.

Many utilities with customer densities of thousands of customers per square mile have centralized control centers with SCADA control and monitoring of their distribution systems and automatic outage management systems to identify area outages on the basis of reported phone numbers. However, NWE–M is able to handle outage calls without all the expense of a distribution control center, a SCADA system, and an OMS system because NWE–M has, on average, only three electric customers per square mile. A centralized distribution dispatch center may not may be effective at NWE–M due to its extremely large territory. Therefore, although a distribution dispatch center and SCADA and OMS systems may improve reliability by reducing the time to respond to large outage events, the very high costs to install these systems likely cannot be justified.

The divisions do their own distribution planning, engineering, and maintenance work. Central Distribution Engineering provides engineering standards, analyzes distribution system critical integrity data, and approves all division capital projects. There is no formal, internal quality control program to assure compliance to distribution engineering and planning standards.

NWE–M prepares distribution engineering standards centrally and provides them to the division engineers. However, central engineering does not verify full division compliance to these standards.

Distribution planning is a division function, and NWE–M does not provide formal planning guidelines for division planning engineers. Central Distribution Engineering does not verify the consistency of distribution planning. Also, there is no formal connection between the division distribution planning and the central transmission planning groups, except that distribution management receives a monthly substation transformer loading report from the transmission planning group. NWE–M does not have a distribution SCADA system and it is doubtful that the cost to install SCADA for planning data is justifiable. Therefore, division planners generally rely on the substation transformer loading reports and manually read meter readings for feeder loading data. However, the Billings and Bozeman Divisions have installed programmable relays (which are more reliable than the old electro-mechanical relays) on many of their feeders that allow them to read feeder loads via the internet. The Billings Division is using software that automatically tabulates feeder peak loads The Billings method appears to be a good possible solution for obtaining loading data timely, accurately, and economically. Planners seem to learn about future load growth by way of informal discussions with division new business personnel. This informal method for distribution planning has worked because the NWE–M distribution system has a lot of excess capacity. In fact, NWE–M forecasts only 3 feeders out of the 671 to be loaded in excess of 90 percent of capacity on the peak load day forecast for 2005.

c. Findings and Recommendations

Liberty found that NWE–M operates and engineers its electric distribution system consistent with good utility practices. However, Liberty found that NWE–M's distribution planning methods were not consistent with good utility practices. The following paragraph provides a recommendation to address the process that Liberty believes is not consistent with good utility practices.

Recommendation II-8: Distribution System Planning

Liberty found that distribution load monitoring and planning methods are somewhat haphazard and work only because the engineers have been innovative and communicate well, and because the system load growth has been slow in most service areas. For example, the faster growing Billings Division is much more advanced than other divisions by its use of a daily peak load monitoring system. However, NWE–M's current informal planning processes could lead to circuit loading problems in the future. Because there is little centralized distribution planning leadership and little centralized verification of either the planning or the engineering work performed by the divisions, Liberty recommends that NWE–M: (1) formalize the processes of forecasting distribution load growth up to 5 years or more (the process should identify growth projects and be tied in with transmission system planning); (2) use programmable relays to monitor feeder loads on a real-time basis (this would also improve distribution feeder relay reliability); and (3) assure that all distribution forecast and planning methods and engineering work are the same company-wide by putting into place tentative NWE–M plans to standardize division organizations where the division planning engineers will be under a centralized distribution planning manager, and the division distribution design engineers will be under a centralize engineering manager.

Liberty also provides the following suggestions for NWE–M's consideration for improvement.

- Much of the in-house field workforce is aged and many of the linemen will be retiring in a few years. Also, production and willingness to work overtime might improve if NWE–M hired more youth into its field workforce. Liberty suggests that NWE–M start hiring young linemen and apprentices to reduce the average age of its field workforce.

- NWE–M indicated that it was considering staffing centralized distribution planning and design positions to directly monitor division planning and design work. Liberty suggests that NWE–M consider combining transmission and distribution planning in part to take advantage of the innovative techniques used by transmission planning engineers.

- Engineering work loads may be causing delayed new connects and quality problems on distribution jobs. Liberty suggests that NWE–M consider increasing division engineering personnel to improve both the timeliness and quality of division engineering design work, and to provide more face-to-face time with crews.

2. Inspection, Reliability, and Maintenance Programs

a. Introduction

A utility should inspect and maintain the distribution system to satisfy NESC requirements and to provide reliable service to its customers. A utility should design inspection programs to identify defects that, if left un-repaired, might result in risk to safety, equipment, and reliability.

Designing logical and thorough inspection and maintenance programs, and compliance to those programs, are important to safe and reliable transmission system operation.

b. Evaluation and Analysis

Some of NWE–M's 671 distribution feeders are very long. For example, one feeder is over 177 circuit miles long. Like the transmission system, much of the distribution system is very old (distribution engineering could not identify equipment age). Although NWE–M replaces old equipment upon failure, as part of system growth and public improvement (*e.g.*, road widening), or as part of 4 kV to 12 kV conversions, the company has not been proactive or consistent in focusing programs on extending equipment life or replacing old deteriorated equipment. This includes the replacement of poorly performing 1970s underground distribution cable and bad poles. The system critical integrity work performed over the last few years was very selective and did not substantially improve overall system conditions.

However, an ugly pole does not necessary need replacement. Liberty inspected a few examples of old distribution feeders in Park City, Billings, and Bozeman. Liberty inspected cedar poles that appeared to be in poor condition but had been inspected and were sound. These poles had treatment and inspection tags and sounding marks. Treated cedar poles can last a very long time even though they may appear ugly with cracks and other surface damage. However, Liberty identified some missing pole equipment items that NWE–M did not include in its inspection programs. These items included missing guy wire guards and markers and ground wire moldings on old poles in locations where their use would be consistent with good utility practices. Liberty also identified an un-fused feeder tap and several examples of trees either touching conductors or trees very close to the conductors.[4]

NWE–M experienced 7,061 sustained outages on the distribution system during 2003. NWE–M identified the causes of these outages as shown in the table below. A large portion of these causes were equipment failures, animals, and trees. One quarter of the equipment failures were due to URD cable failures.

[4] NWE–M reported that it had scheduled trimming at those locations observed by Liberty.

Outage Cause	Count	Percent
System-Equipment Failure	1,631	23.10%
Nature-Lightning	860	12.18%
Nature-Wind	678	9.60%
Animal-Squirrel	553	7.83%
Nature-Tree In Line	531	7.52%
Animal-Other Bird	438	6.20%
Unknown	409	5.79%
Nature-Snow/Ice	318	4.50%
Nature-Limb In Line	199	2.82%
System-Other	187	2.65%
Public-Vehicle Hit	183	2.59%
Animal-Raccoon	147	2.08%
Other (less than 2% each)	927	13.13%
Total	7,061	100.00%

System Equipment Failure by Source	Count	Percent
Conductor - UG	401	24.59%
Connector/Splice	223	13.67%
Cutout/Disconnect	216	13.24%
Conductor - OH	180	11.04%
Insulator	127	7.79%
Arrestor	108	6.62%
Transformer	107	6.56%
Fuse	88	5.40%
Other (less than 3% each)	181	11.10%
Total	1631	100.00%

NWE–M's annual inspection programs specify the company's distribution maintenance requirements. These programs include performing annual patrols of 80 percent of the entire distribution system for obvious hazards on the lines, poles, and equipment including vegetation management needs, and detailed ground inspections of lines and poles on 20 percent of the system. The programs call for treatment of 5 percent of the poles every year. The inspection programs includes identifying and prioritizing pole and cross arm conditions, right-of-way encroachments, tree clearances and other vegetation problems, line clearance problems, conductor and shield wire defects, pole hardware and insulator defects, ground wire integrity and measuring ground resistance, and guy defects. The procedure does not include verifying that guy guards and ground wire moldings are in place, as appropriate. The division integrity coordinator manages capital programs, and schedules O&M emergency and minor repair work. The centralized distribution engineering manager must approve capital work to be included in the critical system integrity program.

As indicated above, NWE–M's program indicates that it should be completing detailed ground inspection on 20 percent of its distribution poles per year, and its inspection and pole treatment maintenance on 5 percent of its distribution poles per year. The tables below show the actual inspection completion rates.

Overhead Detailed Inspections

Division	**1999**	**2000**	**2001**	**2002**	**2003**
BIL	32	10	22	18	1
BOZ	8	3	4	14	0
BTE	12	8	17	3	0
GF	7	7	6	10	0
HAV	4	11	7	6	0
HEL	2	20	3	8	0
LEW	4	8	11	8	4
MSL	0	2	2	3	0
System	69	69	72	70	5
Percent of Total	10.28%	10.28%	10.73%	10.43%	0.75%

Overhead Test & Treat Inspections

Division	**2001**	**2002**	**2003**
BIL	5	4	0
BOZ	0	0	0
BTE	0	0	0
GF	3	5	0
HAV	4	1	0
HEL	3	3	0
LEW	6	9	0
MSL	2	3	0
System	23	25	0
Percent of Total	3.43%	3.73%	0.00%

Specifically Recorded Pole Replacements

Division	**2002**	**2003**
BIL	100	19
BOZ	166	36
BTE	177	15
GF	145	40
HAV	174	3
HEL	118	14
LEW	162	23
MSL	144	55
System Total	1,186	205

The last of the three tables indicates the number of distribution poles replaced in 2002 and 2003.

NWE–M assigns distribution maintenance work by order of priority. Immediate hazards to the public or property have highest priority, followed by repairs to avoid an outage, then those that crews should repair when they are in the area. Distribution poles and cross arms with reduced strength and requiring replacement are prioritized as either 4-rated or 5-rated (bad poles). NWE–M has 3,607 known distribution poles with a 4-rating and 35 known distribution poles with a 5-rating, out of about 350,000 distribution poles. After a supervisor verifies pole and cross arm ratings, the company includes bad poles and cross arms and repairs to avoid outages in the System Integrity Program for additional analysis. The central distribution system integrity engineer first evaluates and prioritizes each circuit the basis of the past year's reliability indices, cause of outages, the number of customers, and feeder criticality to identify and prioritize the worst performing feeders. NWE–M developed its own software for measuring reliability of all circuits, and for selecting feeders for its worst performing feeder program. After it completes integrity work, the integrity engineers can track resulting reliability improvement. However, NWE–M has not fully implemented division input of integrity work completed into the new critical integrity tracking system. Also, the divisions do not report the completion rates of minor maintenance identified by the inspections (and not included in integrity projects) to central engineering. The number of feeders included in a year's integrity work is limited by the capital funding made available.

NWE–M does not currently have a written policy addressing animal correction practices (except for raptors). However, NWE–M informally addresses concerns with poor reliability dealing with animal-caused outages and has animal correction standards. The company tracks animal-caused outages separately in its outage database and identifies circuits with high outage counts for correction within the current year. NWE–M said that it takes into account the number of outages, the number of customers on the circuit, and circuit reliability statistics. If a circuit is experiencing frequent outages due to animals in an area, operating areas request dollars through a central animal correction pool for immediate action. When it identifies a circuit in need of animal correction, it installs insulated jumper connections and insulated bushing covers for transformers, arrestors, and cutouts. However, this process has not appreciatively reduced the overall large number of outages caused by animal contact.

To protect large birds and reduce the number of outages caused by contact of these birds with conductors, NWE–M instituted a raptor program. Whenever utility personnel observe raptors nesting on poles or structures and there have been reliability problems on the circuit, NWE–M builds nesting platforms away from the conductors, or takes some other action, to reduce the possibility bird to wire contact.

Each operating division identifies the circuits for proactive tree trimming. Each area identifies its proactive tree trimming requests by evaluating circuit customer count, circuit outages, and circuit reliability measures to prioritize the projects in order. NWE–M said that for 2004, it started a 5-year tree trimming cycle, using its tree trimming contractor, on its distribution systems in the Butte, Great Falls, and Missoula divisions. In order to ensure greatest effectiveness, it patrols each program feeder to identify each area of the feeder that requires trimming. In addition, NWE–M is addressing "hot spots" with its own crews.

NWE–M was not able to identify the percentage of its 15,000 miles of distribution overhead lines exposed to trees. However, it said that it had identified the need to collect this data in its system integrity program. NWE–M was able to indicate the number of feeders program-trimmed. Out of its 671 feeder circuits, it program-trimmed 52[5] feeders in 2002, 9 feeders in 2003, and will trim 42 feeders in 2004. Therefore, it will have trimmed about 15 percent of all feeders during this three-year period.

NWE–M has an informal "three strikes and you're out" policy that addresses concerns with poor cable reliability. It is NWE–M's policy to identify a cable section for replacement if the section had three failures in the last two years. If a cable has had three or more failures over a longer

[5] Liberty included circuits in 2002 and 2003 when the company trimmed them 50 percent or more.

period of time, the company submits the cable section through the budget process for replacement using NWE–M's system weighting factors, based on cable failures of the circuit, number of customers served by the circuit, and reliability measures. NWE–M also evaluates cable circuits feeding schools, hospitals, and other major facilities on a case-by-case basis and in some cases replaces it on the second failure within a three- to five-year time frame. However, this process has not appreciatively reduced the overall large number of outages caused by cable failures.

As indicated in the 2003 outage cause tables above, URD cable failures are responsible for about 15 percent of all outages caused by equipment failures and about 6 percent of all outages. In 2002, there were 347 cable failures and the company replaced 19 cables. There were 400 cable failures in 2003 and the company replaced 7. NWE–M reported that it has about 157 miles of this pre-1980 cable. The estimated cost to replace all 157 miles is $7,000,000.

NWE–M reported that it spent the amounts shown in the table below for distribution maintenance in 2001 through 2003. The 2004 amounts are budgeted funds.

Year	Distribution Integrity ($)	Distribution Maintenance ($)	Distribution Tree Trimming ($)
2001	13,636,992	12,319,723	1,546,809
2002	12,814,635	8,589,583	1,253,496
2003	12,916,246	8,968,725	1,049,623
2004	16,039,049	11,263,820	1,643,487

NWE–M funds its distribution system programs on the basis of its work priority system that has nine priority levels. The first four priorities are those necessary to do business—emergency response, outage restoration, hot-spot tree trimming, government required work, and new business. Capital level 5 priority work includes the critical system integrity work. However, inspections and routine maintenance are capital priority level 8. NWE–M reported that when funds are limited, it completes only some of the capital priority 5 work at that time. NWE–M reported that it has encountered funding limitations that restrict its ability to get capital priority 6 through 9 work performed in any single year. However, NWE–M said that it increased the priority of some lower priority work when warranted.

c. Findings and Recommendations

Liberty found that NWE–M's distribution inspection and maintenance, and reliability programs are only partially consistent with good utility practice. The following paragraphs provide recommendations to address processes that Liberty believes are not consistent with good utility practices.

Recommendation II-9: Cable Failures

In 2003, underground cable failures caused about 15 percent of the outages caused by equipment failures and about 6 percent of all outages. There were 400 cable failures in 2003 but only 7 replaced. Most utilities have the same problem with URD cable installed in the 1970s, and have implemented dedicated URD cable replacement programs. URD cable replacement criteria usually include replacing cable when one section fails two or three times. They also replace other sections if those other sections are of the same type in a loop. Reliability indices determine cable selection priorities. Liberty recommends that NWE–M evaluate reliability improvements that it could obtain from a better funded URD cable replacement program, and consider making it a primary critical system integrity program separate from the worst performing feeder program. This may have a greater immediate effect on overall reliability than does NWE–M's efforts with regard to the worst performing feeders.

Recommendation II-10: Animals

In 2003, animal and bird contact caused about 20 percent of the outages. Most utilities address animal-caused reliability problems with written programs. Although NWE–M says that it informally installs animal protection devices on the basis of reliability indices, and has a raptor protection program, it appears that the company can still do more to reduce outages caused by animals. Liberty recommends that NWE–M have a more proactive animal protection program.

Recommendation II-11: Distribution Tree Trimming

Trees accounted for over 8 percent of the distribution system outages in 2003. NWE–M reduced funding for tree trimming in 2003. During the 2002, 2003, and 2004 period, NWE–M will have program-trimmed only 15 percent of its distribution circuits. Liberty has observed that other utilities have determined that all lines exposed to trees must be program-trimmed at least every 4 to 5 years. Whenever a utility reduces tree trimming efforts, it requires more time and funds in the future to minimize reliability problems caused by trees. One rule-of-thumb says that $1 saved on tree trimming this year will cost an additional $1.25 the next year. Although NWE–M has started a 5-year cycle in three divisions, Liberty recommends that NWE–M put extra funding to catch up on the trees that it missed when it reduced tree trimming. Liberty also recommends that NWE–M base its tree-trimming cycles on tree types, terrain, and voltage, and supplemented by an annual inspection program to identify hot spots. Although most utilities have 4- to 5-year tree-trimming cycles, the appropriate NWE–M tree-trimming cycle would depend largely on specific tree growth rates in Montana.

Recommendation II-12: Distribution Pole Maintenance

NWE–M distribution pole inspection programs include identifying poles with reduced strength by applying either a 4-rating or a 5-rating (bad) poles, although the programs do not indicate a pole replacement timetable. It has only 34 known 5-rated distribution poles on its system, but it has 3,607 4-rated distribution poles. It replaced 1,186 distribution poles in 2002 and 205 poles in 2003. NWE–M uses data on 4-rated and 5- rated poles in part to prioritize feeders included in annual critical integrity programs. However, some 4-rated and 5-rated poles may not be on high priority feeders, and therefore NWE–M will not replace them on a timely basis in compliance with good utility practice. Because bad poles can have safety concerns, Liberty recommends that

NWE–M develop methods for identifying schedules for replacing these poles based on safety concerns as well as criticality, and to replace bad poles based on these determinations even when they are not included in system integrity projects. Liberty also suggests that the distribution pole rating system be common with the transmission system, which only has 4-rating levels.

Recommendation II-13: Compliance to Inspection Schedules

NWE–M has not fully complied with the schedules set forth in its distribution system inspection programs. Its distribution feeder inspection programs require that the detailed inspections occur at the rate of 20 percent of the system per year, and the inspect-and-treat inspection occur at the rate of 5 percent per year. NWE–M performed the detailed inspection from 1999 to 2002 at the rate of only 10 percent per year, and the inspect-and-treat inspection in 2001 and 2002 at the rate of only 3.7 percent per year. In 2003, the company performed practically none of these inspections. Liberty found that being non-compliant with its own inspection program schedules is not good utility practice. Liberty recommends that NWE–M give its electric distribution inspection programs the same funding priority as it does its critical system integrity programs.

Liberty also provides the following suggestions for NWE–M's consideration for improvement.

- The divisions track distribution, substation, and transmission minor maintenance tasks in different, haphazard ways, with no one verifying, system-wide, the completion rates of minor maintenance tasks identified by the inspection programs. Division reporting of integrity program tasks performed is incomplete, preventing central distribution integrity engineers from fully evaluating the effect of work performed on future reliability. Liberty suggests that NWE–M consider staffing the position of division liaison engineer with the task of identifying best practices, making practices more common, and providing some quality control. Or, NWE–M should implement its plan to have distribution and substation integrity, maintenance, and planning managed centrally.

- Liberty observed some poles without guy wire guards and markers, and without ground wire moldings, in locations where their use would be consistent with good utility practice. Including these items in NWE–M's distribution pole inspection programs would be consistent with good utility practice. Some utilities include installing guy wire guard and markers where appropriate as part if their ground inspection programs. The installation of pole ground wire moldings, where appropriate, could be also included in the ground inspection program. Liberty suggests that NWE–M include the appropriate installation of guy wire guards and markers and ground wire moldings as items included in its pole inspection programs.

III. Gas Transmission and Distribution

A. Gas System Overview

NWE–M's natural gas service territory covers approximately 73,000 square miles in 28 of Montana's 56 counties. Six divisions, Billings, Bozeman, Butte, Great Falls (including the Havre district), Helena, and Missoula (including the Kalispell District) served approximately 162,000 distribution customers at year-end 2003. NWE–M's gas supply is approximately 55 percent Canadian and 45 percent domestic; on peak, some 50 to 60 percent is storage gas.

NWE's gas transmission system, all within the state of Montana,[6] includes approximately 2,000 miles of pipeline and three storage facilities. The system has pipeline interconnections with NOVA TransCanada Pipeline and Encana and Havre Pipeline Company to the north, Williston Basin Interstate Pipeline Company to the east, and Colorado Interstate Gas Company and Energy West to the south.

The heart of the transmission system is a 16-inch pipeline from Main Line Compressor Station No. 1, near Cut Bank (close to the Canadian border) to Butte. Originally constructed in 1931 and replaced in 1987, this main pipeline has a capacity of 150 MMcf/day[7] at its maximum allowable operating pressure of 1,170 psig. Supplied by 16-inch connections to gas supplies from Canada at Carway and Aden, Alberta, and the Cobb Storage Field north of Cut Bank, the Main Line pushes gas as far south as the former copper-producing areas of Butte and Anaconda, as far west as Missoula, and as far east as Bozeman. The north end of the system also connects to a Canadian supply at Loomis, Saskatchewan, and to Montana production in the center of the northern half of the State. The Company's small Box Elder Storage Field is also located at the northeast end of the transmission system.

The company installed most of the remaining transmission lines in the 1950s, 1960s, and 1970s. At its southeast end, the transmission system connects to Colorado Interstate Gas Company, Energy West Resources, and Williston Basin Interstate Pipeline Company. The Company's Dry Creek Storage Field is located at the southeast end of the transmission system. During peak periods, gas flows west from those interconnections to Bozeman, which is about the null point of the transmission system, *i.e.*, gas flowing from the north meets gas flowing from the southeast at Bozeman.

Laterals serve the load centers at Kalispell and Missoula, Kalispell from the main connection to Carway, Alberta, and Missoula from the Main Line. Both of those load centers are experiencing growth, which is straining the capacity of the laterals. NWE–M is adding looping to both the Missoula and Kalispell laterals this year. Bozeman is also growing, but its location at the convergence of flow from two directions has meant that its growth has been easier to accommodate.

[6] As an intrastate (Hinshaw) pipeline, NWE's gas transmission system is exempt from FERC regulation.
[7] One million cubic feet per day

The design capacity parameter of interest for the storage fields is their capacity to re-deliver gas to NWE–M's markets on a peak day. Those capacities are:

Peak-Day Delivery Capacities

Storage Field	MMcf/day
Cobb	140
Dry Creek	40
Box Elder	5
Total	185

Of the 185 MMcf/day capacity, NWE–M allocates 122 MMcf/day to the distribution utility, and 38 MMcf/day is under contract to third-party customers for storage services. The balance, 25 MMcf/day, is a peak-day reserve.

In 2000, NWE–M re-optimized the balance between base gas, working gas, and withdrawal capacity, in light of the higher value of the base gas. At the current optimization level, the company assigns storage customers, including the utility, about 75 MMcf of working gas storage capacity for each 1 MMcf/day of withdrawal capacity. That is, each customer is entitled to store about 75 days' worth of gas at its contracted maximum withdrawal rate.

Liberty visited five of the company's eleven compressor stations, including the two largest ones on the transmission system (Main Line No. 1 and Main Line No. 3), and the largest storage-area station (Station W in the Cobb Storage Field). Liberty also visited the compressor station and natural gas liquids recovery and storage facilities owned by Omimex and maintained by NWE–M,[8] the company's North Area service facility at Cut Bank, and the West Area service facility at Deer Lodge.

B. Transmission and Storage

1. Organization

The Gas Transmission and Storage (GTS) unit reports to the Director of GTS who is one of five reports to the Vice President, Transmission Operations (both electric and gas operations). Reporting to the Director are managers of Gas Storage and Field Operations, Engineering and Construction, and Gas Operations. As of April 1, 2004, GTS employed a full time staff of 70. Approximately 50 percent of the staff is a field force assigned to the Cut Bank/north area, 30 percent to Butte, and the remainder to Deer Lodge, Dry Creek and other field locations on the southern part of the system.

GTS has a self-contained engineering unit within its organization, located at the Energy Building in Butte. Engineering handles facilities design, project management, construction management, code compliance work, planning and forecasting/peak-day planning/system modeling, technical

[8] Montana Power Company constructed these facilities, which are located within NWE–M's North Area service facility at Cut Bank.

aspects of cathodic protection and metering, and assistance with emergency response. The GTS organization includes seven professional engineers.

GTS has an experienced, stable staff (except for recent losses primarily due to retirements). Most of the management level personnel "grew up" performing GTS or its predecessor organization's functions and are very familiar with transmission and storage operations and code requirements. GTS (and the company in general) benefits from a highly flexible work force, as is necessary for efficient functioning of a rural, geographically dispersed and diverse service area. By "wearing multiple hats" and being trained in multiple functions, GTS is able to maintain a reasonably efficient and productive work force.

2. Capacity Planning

a. Background and Analysis

GTS prepares peak-period demand forecasts for the gas transmission and storage system. The purposes of the peak-period forecasts are: 1) to evaluate the system's peak-period transmission and storage delivery capacity to ensure that peak-period requirements can be met, and 2) to evaluate storage capacity relative to the requirements of the company's customers for firm natural gas utility supply service ("core" customers), and the company's contractual commitments to its third-party customers for gas transmission and storage services ("non-core" customers).

GTS performs peak-period analysis with computer simulation of network flows, using a network flow simulation model from Gregg Engineering. The simulation divides the transmission and storage system into nine segments or "demand areas," each with its own weather parameters. The model includes 50 receipt points, and 130 to 150 delivery points. The design criteria for the peak period are: 1) the peak day is the actual weather experienced on February 2, 1989, and 2) the peak period is the five days experienced from January 31, 1989, through February 4, 1989. GTS adjusts actual flows on February 2, 1989, for changes in the number of customers and use per customer, and uses the result to estimate flows under those conditions. The five-day period is the most prolonged severe weather event ever recorded, and GTS uses it to ensure that storage volume, compression, and piping are sufficient to maintain adequate flows through such an event. GTS prepares simulation model runs for each year of a 10-year forecast period.

GTS prepares data over the summer and performs the peak-period analysis in the fall. GTS checks simulation results against system performance after the winter and re-calibrates the simulation model as necessary. GTS reports that the model typically under-predicts flows by a few percent (*e.g.*, 1.6 percent in 2004).

The simulation reports its results as the sum of peak-day deliveries to all customers. The following table presents the first five years of the most recent forecast.

Forecast Peak-Day Deliveries to Customers
MMcf/day

	2004/05	2005/06	2006/07	2007/08	2009/10
Core customers	229.1	233.4	237.7	242.0	246.3
Non-core customers	78.3	78.3	78.3	78.3	78.3
Total	307.4	311.7	316.0	320.3	324.6

The increase in the peak shown for core customers reflects growth that the company is experiencing in the number of customers for utility service. GTS adjusts this growth for changes in use per customer by re-estimating that parameter every year for each of the nine demand areas. The company originally established non-core customer requirements as actual flows to each customer on the peak day (February 2, 1989). Since that time, some of those customers have adjusted their peak-day contract quantities (Maximum Daily Demand Quantities, or MDDQs), some up and some down. The forecast uses the established MDDQs, as they currently show no signs of increasing.

GTS examines the results of the simulation runs segment by segment. Where capacity is tight, it identifies, engineers, and costs potential system upgrades. GTS feeds these results into the company's capital budgeting process.

Customers with annual consumption of 5,000 dekatherms or greater are eligible to take firm or interruptible transportation service. Most interruptible transportation customers on the NWE–M transmission system maintain a level of firm transportation as well as some interruptible transportation. During the last five years, NWE called two curtailments ("Critical Operating Times") when it interrupted those customers on February 25, 2003, and January 5, 2004. During those winters, the company had 30 and 38 interruptible customers, respectively. NWE–M considers only the firm portions of their loads for planning purposes.

b. Conclusions and Recommendations

Overall, there is adequate north/south capacity on the Main Line and from Butte east to Dry Creek Storage. Capacity is tight off of the Main Line where the system is experiencing growth in Kalispell and Missoula. NWE–M is adding capacity to the Kalispell Lateral via looping this year, and Liberty understands that the company recently authorized a similar project for Missoula for construction in 2004. Bozeman is also experiencing growth, but has adequate capacity available.

Liberty was impressed with the analytical techniques used by GTS in estimating the peak-day flows. Regarding design criteria, actual weather in 1989 probably fits the "coldest day in 30 years" criterion that many gas companies use for peak-day analysis. Liberty prefers a probability-based approach to peak-period specification, but use of the five days in 1989 should be adequate. While changing from the actual period to a probability-based peak-period specification might improve peak-period flow simulation, Liberty cannot be certain that the degree of improvement would justify the cost of making the change.

A concern about the capacity planning process is the lack of involvement of the divisions. It does not appear that the divisions are "kept out" of capacity planning; rather, they do not feel that they need to be involved. There are interface issues between capacity planning at the transmission level and system planning at the division level. One of those issues is farm taps, which Liberty discusses in more detail below. Another is that capacity planning for the transmission system needs a more detailed understanding of load changes in the divisions. Particularly if expansion of the transmission system can be "slowed down" by more sophisticated simulation, that simulation needs to be more informed of the details of changes at the division level.

Recommendation III-1: Transmission – Division Interface

To bridge the planning gap between GTS and the divisions, GTS should host a planning conference prior to the beginning of each heating season. Attendees from the divisions would be from the engineering staffs. The focus initially would be operational planning for the upcoming heating season. That is, what developments in the load in each division will affect operation of the transmission system over the coming winter? These discussions should lead to a better understanding of necessary capital improvements to both transmission and distribution systems, and better integration of those improvements.

GTS and the divisions should also establish periodic meetings on a regular basis, perhaps quarterly, to discuss issues of mutual interest. In addition to the annual planning issue, others include planning updates, farm taps, Lost-and-Unaccounted-for Gas, and standardization of reporting on third-party damages and leak surveys.

3. Transmission Safety Regulations

a. Operator Qualifications

In compliance with the Pipeline Safety Act of 1992, Sections 106 and 205 and the Accountable Pipeline Safety and Partnership Act of 1996, Section 4, the US Department of Transportation Office of Pipeline Safety (OPS) adopted regulations, embodied in 10CFR Part 192 Subpart N, requiring that all individuals who operate and maintain pipelines ("Operators") be:

- *…qualified to operate and maintain the pipeline facilities*
- *Have …the ability to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits.*

NWE–M issued its Operator Qualification Plan ("OQ Plan") on April 20, 2001, to implement the regulations. The Plan describes how NWE–M evaluates the qualifications of individuals performing certain operating and maintenance tasks on the transmission and distribution systems. The company refers to the tasks subject to the regulations and the Plan as "Covered Tasks." A Covered Task must:

- be an operations or maintenance task
- be performed on a pipeline facility
- be performed as a requirement of 49 CFR Part 192

- affect the operation or integrity of the pipeline.

Examples of Covered Tasks include cathodic protection system maintenance (five independent, separately tested tasks), locating pipelines, and leak surveying (separate tasks for walking and mobile).

The Operator must have at least one qualified individual directly involved in or directly monitoring non-qualified individuals performing a Covered Task. To become qualified, an individual must be able to perform the covered task, recognize and react to abnormal operating conditions that he may encounter during the performance of the covered task, and to direct and observe unqualified individuals.

The evaluation of qualifications, which is conducted and documented by individuals designated by management, may include one or more of the following:

- written or oral examination
- observation of performance, on-the-job training or simulations
- current professional certification on the Covered Task.

Contractors are also subject to the OQ Plan requirements, except that they may be qualified by an outside operator qualification program that NWE has audited and found acceptable. Prior to performing a Covered Task, the contractor must submit a copy of the contract employee's operator qualification records to NWE.

In conjunction with Distribution, GTS identified 170 Covered Tasks, administered the required tests, and qualified all its operators as of October 2002. GTS administered a total of 1,670 tests to its employees. The OQ Plan requires periodic retesting at intervals specific to each Covered Task.

b. Integrity Management

Through several rulemakings beginning in 2002, the OPS implemented rules to achieve the following general objectives:

- Accelerating the integrity assessment of pipelines in "High Consequence Areas," (HCAs, explained below)
- Improving integrity management systems within companies
- Improving the government's role in reviewing the adequacy of integrity programs and plans
- Providing increased public assurance in pipeline safety.

OPS designed the rules to provide enhanced protection for HCAs, which are Class 3 and Class 4 locations under 49 CFR Part 192.5[9] or other areas where the potential failure of a pipeline could have significant effect on people or property.[10]

OPS classifies pipelines within HCAs as "Covered Segments," which are subject to the assessment parameters set forth in the rule. Pipeline operators must develop a written Integrity Management Plan that includes:

- Identification of all Covered Segments.
- A Baseline Assessment Plan to assure the integrity of all Covered Segments. The Assessment Plan must identify potential threats to each Covered Segment, and then identify methods to assess the integrity of that segment based on the threats. Acceptable methods include internal inspection (pigging), pressure testing, direct assessment (exposing the pipeline for examination) or other technology that the operator demonstrates provides equivalent evaluation of pipeline integrity.
- A Framework that contains all the required elements of the Integrity Management Program.
- A process to assure continual improvement to the program.
- Provisions to implement industry standards.
- A process to document any changes to the program and to notify OPS as required.

Operators are required to develop the program by December 17, 2004, to complete the assessment of 50 percent of the Covered Segments, beginning with the highest risk segments, by December 2007, and to complete the full assessment by December 2012.

c. Reportable and Non-Reportable Pipeline Incidents

Under Federal Rule 49 CFR 191.5, pipeline operators must report incidents to the Federal Office of Pipeline Safety involving escape of gas, death or injury requiring hospitalization, or property damage greater than $50,000.

During the last five years, NWE had four such reportable incidents:

- 2002: rupture of a 6" pipeline at a river crossing due to scouring.
- 2001: 3rd Party contractor damage to an 8" line.
- 2001: 3rd Party contractor damage to a 3" line.
- 1999: 3rd Party semi-truck and trailer accident that destroyed a gate station, resulting in an outage to approximately 500 customers.

NWE–M reported no deaths or injuries in those incidents.

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[9] The rule specifically defines Class 3 and 4 locations, but generally there are populated areas, areas where the pipeline lies within 100 yards of either a building or a place of public assembly, or where buildings with four or more stories above ground are prevalent.
[10] The rule provides additional guidance as to how to make this determination.

In addition, NWE–M recorded a number of lesser transmission line damages, below the federal reporting threshold level, over the last five years. The following table includes all recorded incidents, including the four listed above:

Year	Line Size	Cause
2003	6"	Corrosion
	6"	Corrosion - leakage in 5 locations on same line
	12"	Material failure (crack in seam)
	6"	3rd party damage
	12"	Leaking weld
	12"	Leaking existing clamp
	12"	Leaking weld
2002	6"	Apparent material failure (failed seam)
	10"	Material failure (leaking seam)
	6"	3rd party damage
2001	2"	Corrosion
	8"	3rd Party damage
	12"	Material failure (leaking seam)
	8"	Corrosion
	16"	Leaking plug
	16"	Leaking plug
	16"	Leaking plug
	3"	3rd party damage
2000	8"	3rd Party damage
	8"	3rd party damage
	6"	3rd party damage
	8"	Damage by company crew
1999	12"	3rd Party damage
	4"	3rd Party damage
	10"	Damage by company crew
	10"	Corrosion

d. Conclusions and Recommendations

GTS appears to have handled the difficult tasks associated with the mandated Operator Qualifications program in a timely and reasonable fashion. GTS has developed and updated a written procedure, identified a substantial number of Covered Tasks, developed and administered tests for those tasks, and developed a record-keeping system for tracking employee qualifications, testing, and other relevant data.

GTS has a good understanding of the requirements of the mandated integrity management program and is in the process of developing the required framework for implementation of the program.

Because of the primarily rural nature of NWE–M's service territory, GTS expects to find only a small percentage of the company's 2,000 miles of pipeline to be Covered Segments. However, it cannot internally inspect most of the lines due to the diameter and configuration, so it will have to use other, potentially more expensive techniques. Liberty understands that the company has not budgeted funds for the performance or the required assessments.

Recommendation III-2: Integrity Management Program

NWE–M should include funding for the Integrity Management Program in its next budget cycle. To the extent that detailed estimates are not available (given that it is a multi-year program), the budget should include a placeholder level.

Recommendation III-3: Third-Party Damages

GTS should supplement the activities of One-Call and take a more active role in dissemination of information with respect to third-party damages to transmission lines. Eleven of the 26 incidents recorded[11] in the last five years were the result of third-party damage, including two incidents caused by company crews. Such incidents are a far greater threat on the transmission system as compared to the distribution system due to the high pressures and volumes. Furthermore, while the company does bill responsible third parties where possible, such billings are unlikely to cover the total, all inclusive cost of the emergency response, to say nothing of the safety risk posed to the public and NWE employees.

NWE–M should support the development of a system of citations and fines for third-party damages to underground facilities. They have proven to be an effective tool in reducing the number of third-party damages and are in effect in a number of states.

Also refer to the discussion of third-party damages in the Distribution section of this chapter.

4. Farm Taps and Gate Stations

a. Background and Analysis

NWE–M serves a substantial number of its retail customers for gas utility service through "farm taps." Farm taps are direct connections to the transmission system, not routed through gate stations. Gate stations have metering and pressure regulation equipment, and often have gas heating equipment for offsetting the cooling effect of the pressure drop and potential icing of the regulators. Farm taps typically have only a valve, a large regulator, and pressure relief from

[11] For these purposes, corrosion leakage in five locations on the same pipeline segment is classified as one incident.

which the service line may run a considerable distance to the customers' locations. The target of farm taps was supposed to be isolated, individual customers, such as farms.

Because of the great distances in Montana, new customers have often been located closer to the transmission system than to distribution facilities. The company's solution to this circumstance has been an extensive use of farm taps. As a consequence, the company's transmission system now has approximately 1,037 farm taps[12] serving 17,260 customers, about 11 percent of the total number of customer accounts. Farm tap customers account for about 10 MMcf/day of peak-day load.

The table below indicates the distribution of farm taps and farm-tap customers among the company's divisions and districts.

Farm Taps and Customers Served

Division / District	Number of Farm Taps	Customers Served
Billings	79	682
- Lewistown	46	
Bozeman	152	7,418
Butte	191	703
Helena	75	2,261
Missoula	110	3,633
- Kalispell	87	804
Great Falls	198	826
- Havre	99	933
Total	1,037	17,260

Farm taps present several difficulties, including the following:

- Gas Accounting: Gate stations have meters that read continuously. Farm taps have no meters—the company measures consumption at the meters of the customer(s) served by the tap. To accomplish reasonable gas accounting, including the identification of Lost-and-Unaccounted-for Gas (LAUF), the company must identify farm-tap customer meters and correct for cycle (monthly) measurements before computing LAUF.

- Maintenance: Farm taps attach to the transmission system, but the divisions maintain them. Code requirements and procedures specify maintenance standards, which are the same regardless of who maintains them. Maintenance practices (*e.g.*, servicing regulators and valves) are the same as servicing similar equipment in other parts of the distribution system and thus are familiar to division personnel. The difficulty comes in record-keeping. GTS' records identify farm taps, but it is not clear that GTS knows who is taking care of them.

[12] As compared to approximately 140 gate stations.

- Capacity planning: NWE–M must remove farm-tap customers from the calculation when it computes use-per-customer from gate station flow information. It must add back farm-tap customers to calculations (such as peak-period requirements) that are a function of the total number of customers.

Farm taps sometimes "grow into" gate stations. The primary intention is to ultimately connect farm-tap customers to the distribution system, and then to abandon the farm tap installed to serve them. Sometimes as a utility adds customers on a farm tap the pipes get closer to distribution facilities. In this case, the utility would connect the farm-tap customers to the distribution system, and retain the farm tap for reliability assurance. Other times, the load on a farm tap will grow, but distribution facilities do not come near enough to connect. In these cases, the utility may have to add a second farm tap to serve the growing load, or add a gate station and eliminate the farm taps.[13]

b. Conclusions and Recommendations

The accuracy of the company's farm tap administrative information is uncertain. There are several codes in the customer information system for identification of customers served by farm taps. However, who is responsible for entering and maintaining the accuracy of that information is not clear.

- Only GTS welders are qualified to weld on the transmission system. Thus, in theory, GTS should know about all farm taps because their welders installed them.[14] The GTS welders are not likely to know which farm tap serves particular customers, however, and are unlikely to have any contact or involvement with the customer information system. Furthermore, many farm taps have been on the system a long time and the accuracy of historical records is uncertain.

- GTS considers the farm tap tees and valves to be part of the transmission system, while anything beyond that (*e.g.*, the farm can, regulator, relief, and distribution pipe) are part of the distribution system. However, the divisions assured Liberty that they schedule and perform the requisite maintenance because their property inventories list the farm taps.

- Customers apply to the divisions for a new service. Processes for identifying whether a farm tap is to serve a new customer, and entering that information into the customer information system, are not clear, and may vary across divisions.

[13] Indeed, this happened recently with a suburb located west of Bozeman. NWE–M installed a farm tap for the first customers, and then a second farm tap was added as the suburb grew. With additional growth, NWE–M replaced the two farm taps with a gate station.

[14] In fact, one of the welders attached to the Great Falls Division transferred in from GTS, and is qualified to weld on the transmission system. The Missoula division also has a transmission-qualified welder.

- If the company connects customers formerly served from a farm tap to the distribution system and the farm tap is abandoned, or is relegated to reliability assurance, then those customers' usage is being measured at a gate station. Processes and procedures for correcting those customers' records in the customer information system are not clear.

The physical farm taps and associated equipment appear to be in compliance with the relevant safety code requirements. However, Liberty is concerned that the very large number of farm taps may present other, potentially significant safety issues and risks. The extensive use of farm taps is not typical pipeline or utility practice. Farm taps were intended for one or a very few customers, typically farms, as the name suggests, where gas was supplied as a concession for allowing a pipeline to cross a farmer's land. But for that trade-off, it would not have been installed. And, the NWE–M situation is unique due to the common ownership of the pipeline and the LDC (local distribution company), a situation in which the pipeline is apparently not permitted to say "no." In Liberty's experience, it would be highly unusual today for an independent pipeline to hook up new LDC customers via farm taps.

As Liberty understands the make-up of a farm tap, there is no flow-measurement or remote sensing. Thus, if a third party were to damage a farm tap, if the regulator suffered from icing, or if the tap experienced an unexpected heavy load, the company might only learn about the incident when customers served by the affected tap called in to report a loss of gas service. Liberty understands that, even with no damage, downstream farm-tap customers occasionally lose service to an outbuilding on cold days when the company adds too many customers between them and the pipeline. Again, the only way the company learns of this problem is when a downstream customer calls in to report his loss of service.

Recommendation III-4: Farm Taps

As a first step, NWE–M should clarify procedures and responsibilities for all aspects of installation and maintenance of farm taps. In particular, as NWE–M uses the farm tap information in the customer information system for load forecasting, emergency response, and perhaps other purposes, procedures and responsibility for the accuracy of that information must be crystal clear.

Liberty also recommends a longer term, more comprehensive effort. The company must know not only where the farm taps are and who is maintaining them, but whether they are creating potentially hazardous situations. Liberty recommends that NWE–M convene a task force of GTS and division personnel to consider all aspects of farm tap installation and use, including at least the following:

- Record-keeping for the farm taps already in existence
- Whether and to what extent to equip current farm taps with flow measurement and SCADA equipment
- Other equipment and use guidelines for existing farm taps, such as limits on load, and conditions for reducing their number

- Policies for installation of future farm taps
- Equipment standards for future farm taps
- Whether NWE–M can make gate stations simpler and less expensive to discourage use of farm taps for non-farm customers.

5. Operations and Maintenance

a. Line Patrol and Maintenance

As required by code, NWE–M performs quarterly and annual pipeline patrols. A typical patrol involves a crew of two to three on foot or four-wheeler. Inspection items include:

- Visual leak survey (*i.e.*, dead vegetation)
- Washouts
- New construction on or near the right-of-way
- Marker posts standing, visible, clean, painted
- Valve box in good condition, locked
- Regulator inspection.

The crew also performs valve maintenance (greasing and exercising the valves) and records cathodic protection reads.

Patrols rely on paper and, to some extent, electronic (CD) maps. GTS expects to have all maps in electronic format by the end of this year. An automated mapping system is in the early stages of development, and the company expects to fully develop that system as it complies with the federally mandated Integrity Management program. GTS engineering keeps transmission line records, including the automated cathodic protection tracking system,[15] in its Technical Services unit.

b. Compressor Station Maintenance

NWE–M owns and operates 45 compressors at 11 compressor stations on its system, 4 electric, 11 gas turbine, and 30 gas reciprocating, at the following locations:

Area	Storage	Transmission	Total
Cut Bank	13	6	19
Shelby	0	9	9
Box Elder	2	0	2
Dry Creek	3	3	6
West Line	0	9	9
Total	18	27	45

[15] As noted earlier, all steel pipe is coated and cathodically protected.

The company also operates and maintains five compressors, three at Cut Bank and two at Dry Creek, for other firms.

NWE–M maintains a Compressor Hour Compliance Report monthly for all of its compressors. This report tracks monthly and annual hours of service, load factors, and permitted running hours.[16]

c. Procedures – Routine and Emergency

For pipeline emergency response (*e.g.*, a pipeline hit), typically the company would get a telephone call into the Call Center. Additionally, a leak would likely be recognized through a pressure drop on the SCADA system. The Manager of Gas Engineering or his backup dispatches an emergency response team that may include employees from distribution operations. Typically NWE–M dispatches the responsible construction supervisor to the site to assess the situation.

d. Odorization

Natural gas is colorless and odorless; the characteristic smell is a result of the injection of odorant into the gas stream as a safety measure. In most situations around the country, pipeline gas is not odorized; utilities typically inject at gate stations. Because NWE–M's predecessor company developed as an integrated transmission and distribution company, with a large number of gate stations and many farm taps, NWE–M injects odorant on the transmission pipeline at about a dozen locations. Gas Operations regularly reviews the results of the "sniff tests."

e. Lost and Unaccounted for Gas (Transmission Level)

Lost-and-Unaccounted-for (LAUF) gas is a catch-all gas accounting category for all gas not captured in other categories. While there is no industry standard for what is included, the industry loosely defines LAUF as the difference between gas purchased and gas sold, and may include operating losses, theft, customer service losses, measurement error, energy to volume conversion error, and company use. The following components are general in nature, and do not necessarily represent the categorization used by all LDCs:[17]

- Operating losses include leaks and maintenance losses (*e.g.*, line purges).
- Theft includes gas used but not metered, via meter bypass, meter tampering, unauthorized tapping of mains or service lines, or similar action.
- Customer service losses typically include metered usage for which the company is unable to find the customer to bill (which exclude uncollectibles, where a customer was billed but has not paid).

[16] Some of the compressors are limited by the number of running hours; for others, emissions levels are the determining factor.

[17] These categories include components of both transmission and distribution LAUF. This chapter discusses distribution LAUF in a later section.

- Measurement error reflects the difference between actual quantities delivered vs. the measurement on customer meters. This is usually a loss since customer meters are typically set so that any metering error will be on the "slow' side, *i.e.*, in the customer's favor.
- Conversion error: LDCs typically take gas from pipelines on an energy basis, measured in dekatherms, and bill customers on a volumetric basis, measured in cubic feet. Since the energy content of the gas ("gas quality") may vary over time as well as across pipelines, this conversion typically utilizes some broad averaging algorithm. Unlike most other LAUF categories, conversion error may be positive or negative.
- Company use represents gas used in company buildings, compressor stations, and other company facilities. Typically, companies meter larger uses such as buildings, but do not meter some smaller uses.
- Timing or matching error may be introduced because customer meter reading lags station metering, sometimes by as much as a full billing cycle. This error may also be positive or negative.

Historically, NWE–M had considered four elements of LAUF: Production, Storage, Transmission, and Distribution. After the divestiture of production and the development of the current organization, GTS now tracks transmission and storage LAUF. GTS recorded the following data for the transmission system on a gas accounting basis:

Year	Percent
1996	1.50
1997	1.22
1998	2.35
1999	1.26
2000	2.19
2001	(0.49)
2002	0.28
2003	0.48

The potential for conversion error is of particular importance at NWE–M, because the gas from its various sources has an energy content ranging from approximately 900 to 1,040 Btu per cubic foot, with an average in the 1,010 to 1,020 range. To deal with this variation, the company has 20 therm zones. Within each zone, the company samples gas and develops a composite conversion factor for billing purposes. It accomplishes sampling using two on-line chromatographs and bottled samples that it takes to a laboratory for testing. NWE–M also funds a consultant to the PSC who samples the gas energy content.

f. SCADA

GTS maintains a transmission-level SCADA system[18] for the entire company (multiple locations in Montana, South Dakota, and Nebraska, and single locations in Wyoming and Alberta) with a total of almost 200 locations, including about 75 percent of the gate stations. NWE activated the current system in October 1999.[19] It includes redundant real-time and historical servers at a primary site and a real-time and historical server at a back-up site. Gas Dispatch uses the primary workstation and a standby backup housed in a limited access location. There are two maintenance workstations at two different sites, and an off-site backup station that the gas measurement group also uses. A vendor performs SCADA maintenance via telephone line.

The gas SCADA system is completely independent of the electric SCADA system, although the equipment shares a common location at the SOCC and a common communications link. The company has no plans to combine the two systems. NWE–M has some distribution SCADA capability, including a gas measurement system for non-core distribution customers that uses dial-up technology to monitor several hundred customers on a daily basis. In addition, all the city gate stations with SCADA have distribution pressure transmitters. The SCADA system also connects to the corporate computer system.

There are about ten corporate-wide users of the system with access limited by special passwords. Only two have full access, while the others have read-only access. Some of the monitored equipment has remote control. GTS has the capability to start, stop, and trim electric and turbine compressor stations at Butte, Deer Lodge, MainLine #3, Station W, Telstad, and Dry Creek, and remotely control a number of transmission control valves.

g. Conclusions and Recommendations

During field visits, Liberty observed that company plant and equipment, including vehicles, appeared to be in good condition and very well maintained. Maintenance records were readily available and in good order. The company maintains skills and capabilities on its staff for performance of all engineering activities, all major maintenance activities, and many construction activities. Operations and maintenance manuals appear to be thorough, comprehensive, and up-to-date.

The gas transmission SCADA computer system appears logical, current, and with reasonable redundancy of server and operating stations. It is appropriate that it is maintained separately from the electric SCADA system first, so that in the event of a problem, NWE–M would not lose both systems, and second, because gas operations tend to get lost or downplayed when combined with electric operations.

Liberty has no recommendations in this area but has the following suggestions for NWE–M's consideration for improvement.

[18] NWE has no gas distribution SCADA.

[19] The original GTS SCADA system was developed beginning in 1989.

- In conjunction with the earlier comments and recommendations with respect to farm taps and SCADA, NWE should consider installing some SCADA capability at all gate stations and farm taps. To the extent that this is not economically feasible, NWE–M should develop a set of criteria as to which locations will have SCADA hook-ups.

- In conjunction with distribution, and as discussed earlier under capacity planning, GTS and the divisions should develop a coordinated, phased approach to analyzing LAUF. This should start with identification of potential major components and development of techniques for measuring or estimating their levels.

6. Scheduling and Dispatch

On a daily basis, Gas Operations develops a forecast and sends it to dispatch in the afternoon for use the following day. Gas Control (dispatch), located in the SOCC, is a combination electric and gas control center, with common supervision from the electric side of the business. NWE–M staffs four desks, three electric and one gas, at all times. Of the 17 controllers employed by the company, 8 are qualified as gas controllers, and 3 of those are long time gas controllers. An experienced gas engineer stationed at the SOCC and the Manager of Gas Operations located at the Energy Building provide gas advice and expertise to the gas controllers.

Liberty has some concern with the placement of gas dispatch in a predominantly electric shop. As mentioned earlier, gas activities have a way of getting downplayed or lost in combined operation. NWE–M has compensated for this by maintaining a gas engineer at the dispatch center, with regular daily contact with the dispatchers, by close coordination with the Manager of Gas Operations at the Energy Building, and by the presence of several "old-line" gas dispatchers on the rotation. Liberty suggests continuation of these practices and a continued awareness on the part of management of the potential pitfalls of the combined operations.

C. Distribution

The distribution system includes 4,892 miles of main, of which approximately 74 percent is plastic and 26 percent cathodically protected steel. NWE has 163,179 services, with approximately 54 percent plastic and 46 percent coated steel. The company has no bare steel main and has never used cast iron pipe on its system.

1. Planning

a. Background

Planning for the distribution system follows developments in loads, as observed by each division. Growth in small-volume load is generally predictable, as it increases linearly with the number of customers. Through marketing contacts and simple observation, the divisions know where new housing and associated commercial activity is located, and can assess whether the distribution facilities in those areas have the capacity to accommodate expected growth.

NWE–M performs specific analyses for larger-volume loads. The engineering group in each division works with GTS to determine whether the transmission and distribution systems can deliver the necessary volumes to the customer's location, and to identify any system enhancements that might be necessary to accomplish the contemplated service.

To evaluate evolving changes in loads, the engineering group in each division monitors the distribution system's performance with pressure recorders. Each fall, the group selects locations for the recorders. Depending on how many areas they are concerned about, the divisions experiencing customer growth might use 12 to 20 recorders through a winter.

NWE–M targets areas where the recorders show pressure drops for additional analysis. The divisions have access to the same network flow simulation software used by GTS for modeling segments of their system that have complicated flow problems. They may address simpler problems with more basic analytical tools such as spreadsheet calculations.

If system enhancements (beyond normal main and service extensions) turn out to be necessary, NWE–M generally performs simulation studies to determine the most cost-effective way of addressing the problem. Simulation studies generally support presentations to the capital budgeting process as a way of demonstrating that the proposed solution is the most cost-effective one available.

b. Conclusions and Recommendations

NWE–M has not connected system planning for normal small-customer growth at the distribution level and capacity planning at the transmission level. The principal consequence of this disconnect is missed opportunities for integrated thinking and consensus about transmission and distribution system improvements. As mentioned previously, Liberty could find no indication of sharing and discussion of the respective performance information. A previous recommendation, under Capacity Planning, addresses this topic.

2. Operations and Maintenance

a. Leak Surveys

The divisions survey their systems for leaks, covering the entire system once every five years, typically 20 percent of the system a year, as required by code. They conducted some survey work more frequently but this was cut back due to financial constraints. They survey business districts and public buildings more often, generally every year. Procedures in the Gas Distribution Operations and Maintenance Manual specify leak detection surveys, leak reporting, and leak repairs. The Manual specifies that NWE–M shall maintain leak survey and repair records in the division or district office for the life of the distribution system. Employees in some divisions carry out leak surveys, but others use contractors. Whether to use employees or contractors depends on whether a division's employees have the time to accomplish the leak surveys, in addition to their other work. Also due to financial constraints, NWE–M brought some survey work formerly done by contractors in-house.

Each division has a Leak Technician, or other responsible individual, who organizes the leak surveys, receives reports when someone finds leaks, and completes service orders for repairs. That individual develops a system (slightly different in each division) for tracking identified leaks to ensure their resolution. Personnel report leak repairs to the Leak Technician, who "clears" the leak report in his paperwork. As specified in the Manual, the Leak Technician generally retains the leak survey and leak repair paperwork; however, NWE–M has not standardized record retention in this area. NWE–M classifies leaks, depending on the severity, as Class 1, 2, or 3. Class 1 leaks require immediate attention, and the individual performing the survey may not leave the site until someone makes it secure, either by repairing the leak or the arrival of a service person. Class 2 and 3 are much less serious leaks, recorded but immediate action is not required.

The customer service information system is the "fail-safe" for ensuring that NWE–M repairs leaks. The Manual provides that a service order is to be prepared for each leak detected. Personnel enter all service orders, including those for leak repair, into the customer service system. Service orders remain in that system until NWE–M marks the requested service as completed. Thus, any un-repaired leaks would show up as "open" service orders.

b. Lost and Unaccounted for Gas

Liberty understands that the divisions have not tracked LAUF, even on an accounting basis, since 1996, when a PSC decision effectively removed LAUF from the rate structure, *i.e.*, it was administratively set at zero. In Liberty's experience and for all the reasons discussed above, a distribution company would likely experience LAUF in the range of 2 percent to 4 percent of gas downstream of the citygate. Compounding the problem at the distribution level at NWE–M is the large number of farm taps, where the volumes of gas delivered into the distribution system are not measured. NWE–M can make a rough estimate of those volumes by using the ratio of the number of farm-tap customers to total gas customers, which is approximately 11 percent. In practice, these factors add up to an inadequate system of gas accounting and tracking which may have cost and safety consequences.

c. Storm Response

Montana weather patterns typically travel west to east, and the company sees the weather patterns when they hit the west side of the system. Occasionally, there are abnormal weather patterns and bad weather may approach from another direction and hit another division first, or they may experience microbursts.

There is no formal policy on weather monitoring or on telephone or other notification between and among divisions. When a storm is coming in, someone may see it on the Weather Channel. During off hours, if a storm is approaching, personnel on duty can call their division supervisor-on-call, who can call other operating areas. The supervisor-on-call contacts personnel for emergency duty as needed. The company also noted that during big storms, some crew members will show up without a call-up.

NWE–M maintains an Emergency Broadcast System for notification regarding major incidents. A message entered by dialing into the system is then relayed into the voice mailboxes of certain executives. However, they will not be aware of the message until they dial into the system.

d. Third-Party Damages to the Distribution System[20]

Third-party damages occur when an unrelated third party damages a utility's buried facilities (although occasionally, utility workers cause such damages). At NWE–M, such damages are the leading cause of distribution incidents, exceeding the sum of all other causes. In 2003, NWE–M attributed 64 percent of all incidents to third-party damage. While the actual numbers and percentages vary state-to-state, the overall picture is similar nationally.

To address this problem, most jurisdictions have developed "One-Call" systems. In a typical scenario, a contractor or other party proposing to excavate calls a toll-free telephone number, and within a given time period, all operators of underground facilities are required to either mark out their facilities or indicate that they have no underground facilities in the area.[21] NWE–M uses an outside locating service for most mark-outs. NWE–M has participated in One-Call (two separate systems covering different parts of the state) for about the last ten years.

However, damages still occur. Typical causes include failure to call One-Call, mis-marks (which can occur due to conditions such as inaccurate maps, inaccurate locates, facilities not on the maps, and marks faded or being covered by excavations), and using powered equipment within the tolerance zone where hand digging is called for.

NWE-M attempts to alert contractors and customers to the possibility of damage to underground facilities through several avenues, including inclusion in construction brochures given to customers who sign up for new service, an annual bill insert, and through partial sponsorship of TV and newspaper advertisements publicizing the One-Call program. NWE–M employees also attend annual contractors' dinners that address the topic. NWE–M notifies the One Call state coordinator about repeat offenders.

In cases where a third party (other than NWE–M or the locating contractor) is at fault, NWE–M states its policy is to bill for all repair costs, including lost gas, associated with the damage. Montana state law does not provide for citations and fines or penalties to such parties. Many states do, and Liberty has found this to be an effective practice to reduce the number of third-party damages.

[20] See also the earlier discussion of third party damages to the transmission system.

[21] In practice, compliance is less than total. Some operators have not joined a one-call system; others do not necessarily respond to mark-out or indicate they have no facilities in the area.

e. Automated Meter Reading (AMR)

In 1997, NWE made a decision to convert its entire electric and gas non-demand meter population to an AMR system. It completed the project in year 2000. Most of the system (approximately 95 percent) uses Itron radio-based Encoder/Transmitter/Receiver ("ERT") meter modules, which eight mobile vans read. Physical configuration of the ERTs is such that the meters retain functioning mechanical registrations. In remote areas, the company uses an alternative device on electric meters, referred to as a "Turtle," which uses power line carrier.

Using the AMR system, the company is able to achieve actual read rates of approximately 99 percent each billing cycle, with the remaining 1 percent being manual reads (actuals or customer reads) and estimates. If an ERT fails (no detection of a read at the receiving unit), NWE–M dispatches a service person. NWE–M estimates a failure rate of about 0.5 percent per year. The company has not developed a formal process for verifying that the ERTs are providing the correct read, that is, a read consistent with the mechanical register.

f. Conclusions and Recommendations

Processes and procedures for leak detection and repair management appear sound. Liberty did observe that some of the Leak Technicians could use some help in leak records management, however, not because of inattention to the task or insufficient priority, but because their skills lie elsewhere.

A sampling of leak survey reports from two divisions found similarly that the general approach is sound, but that the record-keeping needs improvement and streamlining. Documentation and notes on the forms are inconsistent across a sampling of employees and consultants, and NWE–M did not always note follow-up on Class 1 leaks on the forms. Liberty believes this to be a shortcoming of the recordkeeping and not the leak repair process.

In 2002 and 2003, NWE reported[22] 330 and 399 cases of third-party damages. Liberty sampled the Incident Reports for 2002 and 2003 for one of the divisions. In the division reviewed, NWE employed a standard form, which it usually used for the reporting. However, prompts on the form do not identify all the relevant information that personnel should gather, and the recording of information was inconsistent. For example, some forms do not include contractor name and address, whether NWE–M should bill the contractor, indication of follow-up, or whether the contractor is a repeat offender. It is commendable that the company bills contractors for damages they have caused, although it is unclear how universal this practice is.

NWE–M is among the leaders in installing AMR devices company-wide. AMR is particularly suited for a geographically dispersed company and offers significant benefits in addition to efficiencies in meter reading (*e.g.*, fewer estimated bills, a leading cause of customer complaints; evidence of meter tampering, ease of off-cycle reads).

[22] Source: US DOT Annual Reports 2002, 2003.

Recommendation III-5: Leak Survey Records

NWE–M should develop a standardized program and recordkeeping for documenting and responding to leak surveys. The divisions may also need to some clerical assistance to the Leak Technicians to standardize leak records management. Liberty also recommends that NWE–M develop a program to audit leak detection and repair records.

Recommendation III-6: Weather Monitoring

In conjunction with electric operations and GTS, the divisions should institute a program of basic weather monitoring and of communicating weather information between and among divisions. Also refer to the suggestion in the electric transmission section of this report regarding weather monitoring.

In addition, Liberty has the following suggestions for NWE–M's consideration for improvement:

- The divisions should develop a standardized approach and documentation to third-party damage incidents. This should include a standard form with prompts to the NWE–M person as to specific information to be recorded, and should be entered into a mechanized system for tracking and billing. NWE–M would also benefit from knowing what particular activities were the major causes of incidents and should respond accordingly. Also, refer to the recommendation above, in which Liberty recommends that GTS and Distribution should take a more active role in informing the public and providing training on the problems associated with third-party damages. This might include outreach to contractors, such as training sessions, and visits to construction sites.

- NWE should develop a program for sample testing the ERTS for accuracy. As it administers the system, NWE–M has no program to verify the ERT accuracy over time, assuming the devices send out readings that do not fail the basic customer billing tests.

A recommendation on the treatment of LAUF is included in the discussion of Transmission LAUF.

IV. Safety and Environmental Protection

A. Background

It is good utility practice to provide the guidance and equipment that will clearly demonstrate to employees the company's expectations about safely, health, and environmental protection. The goal of a good safety, health, and environment program is not to just comply with governmental regulations, but to have a workforce that will know and use procedures that are safe and healthy, and prevent damage to the environment. A utility's culture should have embedded principles regarding safety, maintaining health, and preventing damage to the environment.

NWE–M accomplishes this by using formal training, a very comprehensive safety and health handbook, posters, periodic safety bulletins, formal annual reports, and pre-job meetings. The company's reminders to its employees about safety are ubiquitous (*e.g.*, poem printed on its company notepads have a safety theme). It has a well-staffed safety department that analyzes accidents and injuries, resolves safety issues, and monitors work activities to ensure that employees follow proper job procedures. This includes procedures for obviously hazardous activities such as lockout-tagout, confined space, trenching, electrical clearance, using personal protective equipment, and handling PCB oils, and for activities that are not obviously hazardous.

NWE–M instills requirements that its employees always consider safety by using its "PAUSE" philosophy:

- P is for purposely Plan safety into the job
- A is for consider the Alternative actions
- U is for Use the right equipment and method
- S is for Stop an unsafe act
- E is for Evaluate the consequences.

NWE's Safety, Health and Environmental Services Department ("Safety") includes 10 Montana safety employees (7 working out of Butte and others covering Bozeman, Missoula/Kalispell, Helena/Great Falls, Billings, and Milltown) and 1 South Dakota employee.

B. Procedures, Publications, and Other Resources

1. Procedure Manual

NWE has a comprehensive *Safety and Health Handbook* prepared by Safety, Health and Environmental Services and last updated October 2002. It provides safety and environmental protection rules and guidelines for all NWE employees on a broad range of subject and issues.

According to the safety handbook, managers are to budget for safety and verify safe work conditions on job sites. Engineers must design hazards out of jobs and visit job sites. Crew leaders are to facilitate good communication, have pre-job or tailboard meetings, identify hazards, plan safe job procedures in detail, and consider hazards and the need for special skills. They must re-evaluate hazards whenever a job changes. Team members must never make production more important than personal well being of a team member.

All employees are required to formally report to division safety personnel unsafe equipment observed.

The Safety and Health Handbook chapter titles, listed below, indicate the comprehensive nature of the handbook.

1. Introduction
2. NorthWestern Energy Safety and Health Policy
3. Safety Responsibilities
4. Drug and Alcohol Program
5. Incident Response, Reporting, and Investigation
6. First Aid/CPR, and Bloodborne Pathogens
7. OSHA Enforcement Authority
8. Contractors
9. Pre-Job Planning
10. Personal Protective Equipment
11. Ergonomics
12. Occupational Health and Environmental Control
13. Adverse Weather Conditions
14. Vehicle Operation
15. Work Zone Protection /Traffic Control
16. Trenching and Shoring
17. Confined Spaces
18. Lockout /Tagout
19. Ladders and Scaffolding
20. Material Handling
21. Hand and Power Tools
22. Compressed Gases, Welding and Cutting
23. Fire Prevention and Protection
24. Explosives
25. Animal and Insects
26. Operation of Specific Equipment
27. Electrical Distribution and Transmission Work
28. Gas Distribution Work
29. Warehouse Safety
30. Office Safety
31. Public Safety
32. Telecommunications
33. NorthWestern Energy Environmental Policy
34. Environmental Challenges
35. Raptors
36. Equipment and Tool Inspection Guide

2. Newsletter

The NWE Safety, Health and Environmental Services Department publishes a bimonthly newsletter, *Safety Facts for Employees*. Typical contents include items of general health and safety interest (*e.g.*, road and vehicle safety, leisure time activity safety, and home safety). Of particular interest is the section on injuries and illnesses affecting NWE employees. Categories include Injuries and Illnesses (Lost Time, Restricted Duty, Medical, Conditions, First Aid Treatments, "Paper Work Only" Injuries, Vehicle Accidents, and Other Incidents (including "Near Misses"). For example, for injuries, the newsletter identifies by location and job title any employee injured on the job, including the date, a description of the injury, and the cause. For vehicle accidents, in addition to the above information, the description also notes any operator error.

3. Observation Cards

NWE supports a program wherein supervisors are strongly encouraged (but not mandated) to perform safety observations of job sites and fill out a "NWE Job Safety Observation Card." Supervisors are to report any observations to the crew during the visit.

Among the notations to be made on the card include check-offs—whether the crew held a tailboard safety meeting, categories for Personal Protective Equipment, general observations, unsafe body position, tools and equipment, and specific categories for electric and gas work. The card also includes an area for specific comments on positive observations, unsafe acts or conditions, and corrective actions taken.

4. Vehicle Safety

NWE–M's fleet falls under the regulation of the US Department of Transportation (DOT) Motor Carrier Safety Administration. The company must ensure that each truck is inspected annually. DOT also requires that the driver conduct a vehicle inspection and prepare and sign a report at the end of each work day. They must report any defects or indicate that none were found. Any defects noted must be repaired and signed off by the next driver before taking the truck out.

Any employee with a commercial driver's license operating a company vehicle is subject to random drug and alcohol testing. The divisions handle the testing but Safety coordinates it. The Safety and Health Handbook fully describe the testing.

5. Other Safety Activities

Other safety activities, communication vehicles, and programs include the following:

- From time to time, Safety e-mails training communications to foremen, who are required to communicate that information to their crews and to notify Safety that they have done so.
- The company conducts "Spring Training" for all crews, including proper emergency response and pole-top, bucket, excavation and shoring activities.
- During the first quarter every year, inspect all equipment (*e.g.*, hot sticks, grounds, and lifting equipment).

- Every vehicle has its own individual inspection report book.
- Safety training is included in the company’s apprenticeship program. Each apprentice has a safety training sheet, and the foreman has to check off training milestones to get approved for various tasks.
- Safety maintains an intranet web site with various safety postings, notifications, and e-mail access.
- Crews are to hold tailboard/tailgate meetings prior to the start of each job, as per the Safety Manual. Recently, the entire company had training to emphasize the importance of tailboard sessions.

C. Safety Performance

1. Electrical

Electrical, fall, and confined space hazards commonly face electrical crews. Utilities should design job procedures to minimize these hazards and protective equipment to prevent injuries.

NWE–M requires that crews always isolate, ground, test, and verify no possible backfeed before working on de-energized equipment. The company only allows “qualified workers,” as defined by OSHA, to work within areas near energized parts. NWE–M requires the use of proper protective equipment when working under prescribed conditions within the minimum approach distances. It also requires linemen to inspect and test poles before climbing and take precautions when handling treated poles. It prescribes OSHA-required fall protection devices for apprentices and indicates procedures for emergency rescue from pole tops and towers. It uses the OSHA prescribed confined spaces procedures when working in manholes and vaults.

NWE–M’s electrical safety procedures comply with OSHA 1910, Subpart R, “Electric Power Generation, Transmission, and Distribution.”

2. Gas

Various hazards including fires, explosions, asphyxiation, falls, powered equipment, and construction hazards also face gas operating employees. Similar to the electric workers, the company only allows experienced, qualified workers to work with natural gas facilities. A sampling of the safety requirements spelled out in the Safety and Health Handbook follows:

- Crews must test confined spaces (*e.g.*, manholes or regulator pits) possibly containing combustible or hazardous atmospheres before entering. Clothing must be of all natural fiber and personnel protective equipment (*e.g.*, fireproof clothing) is required under certain circumstances.

- Crews are required to call the One-Call system for locates before excavating, trenching, plowing, boring, or auguring.

- All gas operating employees are subject to random drug testing, similar to the program for commercial vehicle operators.

3. Key Performance Indicators

NWE–M reported lost time incident rates per 100 employees of 2.36 and 2.30 in 2002 and 2003, respectively. This compares to EEI data for 2002[23] for combination utilities of 2.28 and 3.10 for similar size utilities.

With respect to OSHA reportable accidents, NWE–M reported rates of 6.63 and 5.94 for 2002 and 2003, respectively. This compares to EEI data for 2002 of 4.09 for combination utilities and 5.76 for similar size utilities.

D. Oil Spills and PCB Monitoring

NWE–M maintains a database of oil spills. The Montana Department of Environmental Quality (DEQ) requires a report of any spills over 25 gallons. NWE also reports directly to Environmental Protection Agency (EPA) Region 8 in Denver. The EPA requires a report on any spill involving one pound or more of PCBs.

For the calendar year 2003, NWE recorded seven reportable spills. All involved non-PCB transformer or regulator oil resulting from third-party vehicle damage or weather-related damage to poles or pad mounted transformers.[24] During 2003, the company also recorded 19 incidents, non-reportable to DEQ because they were below threshold limits, of spills of various kinds, transformer oil, and in one case, hydraulic fluid. These incidents involved 13 related to equipment or facility failure, 5 related to weather, and 1 related to third-party vehicle damage.

E. Findings and Recommendations

Overall, Liberty found NWE–M to have a strong and thorough safety program and a safety-conscious culture, with continuing emphasis on the importance of safety and continuing reminders and retraining in safety-related activities.

Liberty has no recommendations in this area.

[23] EEI data for 2003 were unavailable at the time of the audit.
[24] Most substation oil has been removed, but the company still has some equipment with oil containing PCBs in the field. Whenever a transformer comes into the shop, the oil is tested, and any oil containing PCBs is removed.

V. Financial and Cost Analysis

A. NWE–M Business Situation

The Montana T&D operations were part of the Montana Power Company (MPC) until early 2002, when NWE acquired them. A number of major events during the past several years have caused changes in the operations, structure, and financial status of the parent companies of the T&D system, which has in turn influenced the energy delivery businesses.

In 1997, the State of Montana passed legislation calling for the deregulation of the electric business in the state. MPC's settlement with the MPSC in 1999 regarding the implementation of this legislation included the sale of the electric generation business as part of the restructuring process. MPC completed the sale of its generation business to Pennsylvania-based PPL in 2000. As a result of the sale of this business segment, MPC reorganized its utility and headquarters operations in 2000, which included the offering of an early retirement package to the remaining workforce.

MPC also decided to sell its utility T&D businesses in 2000, which would complete its exit from the energy utilities businesses. In late 2000, MPC reached an agreement to sell the Montana T&D businesses to NWE. The MPC parent eventually changed its name to Touch America and invested the proceeds of the sale of the Montana utility businesses in its telecommunications businesses. The sale of the Montana T&D businesses to NWE was closed in February 2002.

NWE began to experience financial difficulty shortly after the acquisition of the Montana T&D businesses. NWE incurred a significant amount of debt as a result of investments made in Expanets (telecommunications), Blue Dot (HVAC), and Cornerstone (propane distribution). NWE's non-regulated businesses adversely affected the consolidated results of operations, financial condition, and liquidity. By late 2002, NWE was significantly over-leveraged, with current and projected income insufficient to support its existing debt levels. For the year of 2002, NWE recorded consolidated losses of $892 million, which eliminated its common equity and resulted in a year-end common shareholder's deficit of $456 million. The new Montana operations contributed $29 million of net income to NWE in 2002.

In early 2003, NWE undertook a series of steps to refinance, reduce, and extend the maturities of its debt. However, the company's financial condition continued to deteriorate, and the performance of the non-utility businesses worsened. In June 2003, NWE announced that it would seek to fundamentally restructure its debt, which was ultimately not successful. NWE filed for Chapter 11 bankruptcy protection on September 14, 2003.

NWE immediately secured a Debtor-in-Possession line of credit of $85 million to provide for the liquidity needs of its continuing businesses. NWE prepared and filed a Plan of Reorganization (POR) in March 2004 that provides a proposed roadmap for emergence from bankruptcy protection in September 2004, and includes projected operations through 2008. NWE's unsecured creditors must approve the POR for the company to emerge from bankruptcy. Liberty considers the assumptions, representations, and financial projections included in the POR to be important indicators of the company's intentions to provide required levels of capital expenditure and operating expense authorizations for the Montana T&D businesses in the future.

B. Capital Expenditures

1. Historical T&D Capital Comparison

The table below provides a high-level summary of actual Montana T&D capital expenditures for the years 1996-2003 and budgeted for 2004. Annual capital expenditures for 2000 are not available because of a conversion to new financial software during that calendar year.

Montana Capital Expenditures

1996-2003 Actuals and 2004 Plan ($ millions)

	1996	1997	1998	1999	2000	2001	2002	2003	2004
Electric									
Transmission	12.9	18.8	12.0	10.7		10.3	9.3	8.8	13.2
Distribution	33.1	30.9	30.7	27.6		24.9	23.4	25.9	26.3
Gas									
Transmission	19.9	4.1	5.6	5.7		8.2	3.4	3.6	6.6
Distribution	9.3	9.1	8.3	7.5		5.0	3.5	5.2	4.9
Utility Communications	1.7	0.6	1.8	1.2		0.7	0.8	0.5	0.6
Common	8.8	6.4	4.8	1.0		4.7	4.8	1.1	5.0
Total T&D	85.7	70.0	63.2	53.8		53.8	45.3	45.1	56.4

Montana T&D capital expenditures have decreased significantly from $85.7 million and $70.0 million in 1996 and 1997, respectively, to $45.3 million and $45.1 million in 2002 and 2003. However, expenditures during these two time periods are not directly comparable due to the following two key accounting changes that occurred in 1999 and 2000:

- The company did not subtract customer contribution advances from capital expenditures for either electric or gas distribution for years prior to 2000. The 1996-1999 annual capital expenditures should be about $3.7 million lower for electric distribution and $1.0 million lower for gas distribution to be comparable with 2001-2004 expenditures.
- Common utility capital expenditures included Demand Side Management (DSM) capital spending through 1998, but not after. DSM capital spending was $4.0 - $4.5 million annually from 1996-1998.

The evaluation of capital expenditure levels over time should also consider major capital projects that could affect year-to-year comparisons. Over a long period of time, a utility system needs periodic major upgrades and concentrated capital spending due to system growth and replacement of key infrastructure. NWE–M identified the following major projects for the 1996-2004 period:

- Missoula to Kalispell loop feed gas transmission project, costing about $14.4 million in 1996.
- The Montana call center in Butte, costing $2.7 million in 1996.
- An electric transmission project in Thompson Falls for a 50 MW generation addition, costing $3.3 million in 1997.
- The Montana capital budget includes the following major projects for 2004:
    - Three Rivers/Jackrabbit Transmission $5.4 million
    - Laurel substation and related (Billings) $2.4 million
    - Lewis & Clark Gas Transmission Loop $2.5 million
    - BC Generation gas transmission $1.1 million

Montana T&D capital spending decreased significantly starting in 1998, even without adjusting for inflation. Capital spending levels decreased by an additional 16 percent from 2001 levels in 2002 and 2003, before recovering with a 25 percent budgeted increase in 2004.

2. Capital Spending Constraints

NWE–M indicated that conceptual limits on capital spending have been a factor in capital planning for a number of years, including the budgeting processes of the old Montana Power Company. One of the driving factors for limiting Montana Power's capital expenditures in the late 1990s was that the utility had not been earning its authorized utility rate of return. In an attempt to earn the authorized rate of return, Montana Power had a generalized planning limit for annual capital expenditures of no more than depreciation levels. NWE–M employees recall this generalized limit as not being absolute, and that discretionary capital projects, such as the installation of SAP financial software in 2000, had to meet economic value added criteria on a stand-alone basis.

The company's business plans indicate that Montana Power began to institute reductions in capital spending around 1997. The 1998 business plan, for instance, presents actual capital spending for the Distribution Business Unit on a historical basis for 1994-1997, and projected for 1998-2002. The historic capital spending for distribution was between $45.2 and $50.5 annually for 1994 through 1996, and fell to $42.8 in 1997. Montana Power projected reductions in capital spending for that business unit in 1999-2002, when it planned on spending only $36.6-$38.3 annually. Most of the reductions, about $4.7 million annually, were due to the end of the DSM program in 1999. However, the plans also noted that:

> *…the base case plan scenario will require us to do much more with less and create additional efficiency improvements in order to meet the EVA EI* (economic value added expected improvement) *target for the business unit.*

> and

> *…the budgets are held flat (at the 1998 level) in both 1999 and 2000. Thus, in real terms, the capital budget is reduced approximately 2.5 percent in 1999 and 2000. After 2000, the capital budget is increased 2 percent for the remaining two years of the plan. It will take continued and deliberate efficiency improvements in order to meet the capital level targets.*

The 1999 Montana Power business plan focused more on capital expenditure reduction and cost control. The company planned the electric and gas distribution business unit capital budget at $9 million less than the 1998 budget, with the restructuring of T&D and the transformation of the DSM programs to universal service causing $5 million of the decrease. The electric transmission group committed to maintaining its capital spending approximately equal to depreciation expense. Each of the subsequent Montana Power business plans through 2002 repeated this capital spending limitation for the transmission group. The 2000 business plan included this passage:

> *Capital plans for electric transmission will continue at about $11 to $12 million per year for the next several years. This is roughly equal to annual depreciation expense for MPC's transmission system. Although this level of capital spending does not allow for immediately addressing all reliability issues, it is a level of spending that can be accommodated without placing undue pressure on transmission rates.*

The 2000, 2001, and 2002 Montana Power business plans brought the electric and gas distribution operations under the same depreciation-related target for capital planning purposes. The distribution business planned to spend "slightly above the forecasted depreciation levels" in 2000 and 2001. For 2002, the business plan reported that, "[T]he Utility (including all electric and gas, transmission and distribution) continues to plan for capital at or below the depreciation levels."

Following the close of the acquisition, NWE–M continued Montana Power's planning practice of restricting utility capital spending to depreciation levels in 2002 and 2003. NWE-M employees noted that at a high level, senior management believes that if it holds utility capital spending at depreciation levels, it can achieve stable rates. The company also noted the balancing act of utility earnings versus system reliability, and commented that spending levels higher than depreciation would logically be required due to inflation, as offset by productivity gains.

3. Capital Prioritization

NWE–M has a work priorities system that is a key framework for both the capital expenditure and operating expense budgeting processes. This subsection deals with capital expenditure priorities; however, NWE–M uses the same prioritization scheme for operating expenses. NWE–M began using the system for T&D in the 2003 budget year. NWE–M emphasizes that this is a relatively new process intended to channel thinking and that it will require more development and education to gain consistent use of the process.

NWE–M's documentation for the prioritization process includes the following key passages:

- *Budgets are created based on system needs determined by performance indicators within the system. Similar to a patient describing what is wrong to the doctor, performance indicators identify important issues within the system.*
- *Team members at Northwestern Energy have developed these work prioritization guidelines to help accommodate the prioritization process.*
- *Asset Management designed this brochure to help individuals understand the criteria for placing a task within a priority. It is also designed to explain how priorities are fluid and adjust as circumstances change. By reviewing this information, individuals should be able to designate a priority of 1 through 9 for each work assignment at that point in time.*
- *Northwestern Energy has developed nine classifications for all of its work. These assignments range from 1 to 9. Number 1 is work associated with responding to emergency, life-threatening situations while number 9 is work tied to performing routine, aesthetic improvements to equipment.*

The following characterize the nine work priorities:

Priority 1, Emergency Response – Work required for employees to (respond to) emergencies that threaten lives or property. The company cannot plan but must expect these activities.

Priority 2, Service Continuity in Jeopardy – Work required to avert an immediate impending disruption of critical elements of the company's systems that deliver energy or control information. The company typically identifies and monitors these situations before they occur; but at a certain point, they need immediate attention to prevent them from escalating into an emergency that threatens lives or property.

Priority 3, Forced by Others – Work required to satisfy legal and contractual requirements. This includes activities needed to comply with existing laws and regulations or with contracts or other legally binding agreements. Failure to comply with these activities exposes not only the public but employees to potential safety or environmental hazards and it also exposes the company to potential fines or legal disputes. Employees are aware of these requirements.

Priority 4, New Business – Work required to extend or improve service as requested by a customer. This work includes energy customers as well as employees and strategic partners. The service includes energy systems and information systems. The company can forecast and plan for these activities on the basis of load analysis and growth trends, but emergencies or strategic changes can affect them.

Priority 5, System Integrity Critical – Work required to prevent service interruptions to customers or to prevent failure of business-critical information systems. Employees typically are aware of the need for this type of work. They monitor and track increasing potential for failure of the equipment, vehicles, or software based on deterioration or increased usage. They have determined that the expenditure will avert outage or equipment failure to systems that generate revenue or are the ones considered highly critical by customers or employees. If planned and scheduled, this work typically costs the company less than performing it in an emergency repair situation.

Priority 6, Pro-active Reliability Centered Maintenance – Work activities to prevent interruptions on systems designated as moderately critical to business operations. These systems include the equipment, vehicles, or software that provide backup or redundancy in energy and information systems. This work includes upgrades of equipment, vehicles or software when maintenance costs exceed the cost of the upgrade. Employees are aware of the need for this work and have exhausted economically feasible options to maintain the reliability of the moderately critical system. This work is in response to the degradation of equipment or vehicles, increased usage, increasing maintenance costs, or service quality lower than the company standards.

Priority 7, System Upgrades – Work activities that involve upgrades to equipment, vehicles, and software that the company considers minimally critical to business operations. This work includes high-return productivity enhancements. The company typically identifies and anticipates this work for 2 to 3 years before implementing it.

Priority 8, Routine Maintenance – Work activities that involve non-critical (routine, not performance-based) system inspections, patrols or operating guidelines not directly related to system problems. These activities identify under-used facilities, and include replacement of deteriorated equipment that does not affect reliability or potential non-critical system efficiencies. This includes work to gain productivity enhancements of moderate return.

Priority 9, Routine Equipment Improvements – Work activities that improve the cosmetic appearance of systems, equipment, or facilities. Activities in this area improve the overall appearance of the system; however, they have no affect on improving the basic operations of the system or equipment and do not affect the reliability.

NWE–M explained that priorities 1-4 are non-discretionary. NWE–M plans this work each year on the basis of estimates of storm damage, MDOT highway requests, new growth assumptions, and other blanket capital needs. Because of economic and weather influences, the company does not know the dollar amounts exactly when it puts together the plan. NWE–M considers priority 2 as reactive system integrity expenditures that it needs immediately. However, in the case of capital growth upgrade projects, there may be some expenditure flexibility based on when it needs to complete projects for peak loading seasons and changing conditions. NWE–M includes all new construction and new business extensions required by customers in the priority 4 category.

NWE–M considers the priority categories below Priority 4 to be discretionary. Even though priority 5 is entitled "System Integrity Critical," which does not seem consistent with discretionary work, NWE–M employees indicated that priority 5 projects are "more discretionary" than priorities 1-4, and that the company could defer them by six months or more.

System reinforcement projects that NWE–M has planned years in advance can move up in the prioritization system on a year-to-year basis. Such projects could first appear as a priority 6 or 7, with a "drop-dead" date in four or five years. The project would gradually move up in the priority rankings, depending on load growth and reliability in that area. The Bozeman-area substation project that the company is building in 2004 is as an example of this type of project.

4. Montana Capital Budgeting Process

NWE–M's annual capital T&D budgeting process begins with field requests from various units such as transmission, distribution division, fleet, call center, generation, support services, and facilities, which prepare bottom-up budgets. The field personnel present to the budget managers their "wish list," which includes estimated costs, written justifications, reliability analyses, and economic analyses in some instances. The company required the prioritization of work and projects using the 1-9 categories in 2003 and 2004.

The capital budget committee for each business unit evaluates the bottom-up project list prepared by the field and re-prioritizes as appropriate. It then tabulates and categorizes projects for presentation at higher levels.

Each business unit makes presentations of the proposed capital budget to the Asset Management Capital Budget Committee. This committee assesses the priorities across the various business units and makes changes as necessary. Following this review, senior management at NWE reviews the prioritized list and the risks associated with maintaining reliability and service levels. The itemized proposal includes a running tabulation of the cumulative capital spending at each point on the priority list.

Senior executives of NWE determine the amount of dollars available for capital spending and compare this to the dollar amounts of requests at each priority level. They consider the types of projects that the available dollars would fund and not fund, as well as financial, regulatory, political, and other factors. After evaluations of all factors, management prepares the capital budget recommendations for the Board of Directors.

NWE communicates the results of the process, including the capital limit and projects funded and not funded, to the field budget process participants. Finally, the company enters the approved projects into its financial software for project tracking, spending, and variance analysis.

5. 2003 Capital Expenditure Analysis

The year 2003 was a difficult one for the NWE–M T&D business. In late 2002 and early 2003, NWE was trying to stave off bankruptcy. The extreme financial difficulties obviously had an effect on the 2003 budgeting process, as well as influencing whether planned and budgeted projects were actually completed.

The chart below summarizes the NWE–M T&D business capital request for 2003. The request level of $80.3 million for all nine priority categories was the first Montana capital budget prepared using the NWE budgeting system.

Priority Level	Description	Cash Cost	Cumulative Cost With Overheads
1	Emergency Response	$1.05 MM	$1.32 MM
2	Service Continuity in Jeopardy	$12.58 MM	$17.13 MM
3	Forced by Others	$4.44 MM	$22.70 MM
4	New Business	$13.09 MM	$39.16 MM
5	System Integrity Critical	$19.07 MM	$58.23 MM
6	Proactive RCM	$8.44 MM	
7	System Upgrades	$8.93 MM	
8	Routine Equip. Maintenance	$3.06 MM	
9	Routine Equip. Improvements	$1.71 MM	$80.34 MM

During the 2003 capital budget process, NWE notified NWE–M T&D that the target capital spending for Montana would be $51 million. This budget target meant that NWE would not fund about $7.2 million of the priority 5 requests, nor would it fund any priority 6-9 requests.

NWE–M’s capital planners focused on the priority 5 requests to determine the most effective way to reduce this category. They examined system information such as outages, number of poles, and reliability performance measures to make a sub-ranking within the priority 5 requests. The sub-ranking for each project ran from 1.0 (highest priority) to 5.0 (lowest priority). They were able to include projects below a 2.4 sub-ranking in the 2003 budget and had to defer other projects. The priority 5 budget for 2003 included Facilities at $0.25 million, IT at $0.36 million, Gas Distribution at $0.26 million, Gas Transmission at $0.44 million, Electric Distribution at $7.08 million, and Electric Transmission at $2.62 million.

As financial pressures increased on NWE during 2003, the company looked for ways to conserve cash. However, the company represents that the planned cuts in budgeted capital spending for all of NWE was only to be about $3 million of the total $70 million budgeted for the consolidated company. The company does not have specific materials memorializing the extent or nature of the proposed capital spending reductions. Furthermore, company employees noted that the company re-started numerous projects after the securing of Debtor-in-Possession financing (a line of credit for bankrupt companies) in September 2003.

A review of the actual 2003 capital spending by major category indicated that spending reductions were somewhat disproportional. NWE–M’s growth-related expenditures and unregulated expenditures were actually well above budgeted amounts in 2003. The growth budget is tied closely to the economy, and the company has a policy of meeting all new customer requests. South Dakota unregulated spending was well above budget amounts due to the gas transmission connections of ethanol plants. The company emphasized that the South Dakota unregulated ethanol projects had to project-finance most of their expenditures, and thus were not tapping the company’s dwindling cash supplies. Also, NWE–M indicated that changes in the Montana growth and unregulated expenditures did not have a significant effect on other utility capital spending.

On the other hand, Montana’s electric and gas maintenance spending was well below the budgeted amounts, especially priorities 4 and 5 maintenance spending. Priority 5 spending reductions included reduced spending on fleet purchases, IT purchases, general office and area facilities, and reduced contractor outlays for maintenance activities.

6. 2004-2008 Capital Expenditures

NWE’s bankruptcy will influence the levels of utility capital spending for NWE–M’s T&D operations on an ongoing basis. Corporate debt financings put into place in 2003 place restrictions and limitations on utility operations and spending in order to provide protection for creditors. The most important of these restrictions for the utilities are those related to total corporate capital expenditures. The NWE Debtor-in-Possession financing limits consolidated capital expenditures for continuing operations to $82.5 million from September 19, 2003, until

September 12, 2004. The CSFB financing, which utility assets secure, has a similar limit, and extends the limitation to $85 million for each fiscal year thereafter. The company anticipates refinancing both of these credit facilities upon NWE's emergence from bankruptcy. The company must replace the DIP facility with a new "exit" revolving credit, and the company is also currently evaluating the refinancing of the CSFB debt as soon as possible given favorable current market conditions. The company's current expectation is that the covenants on the new issue debt will be more "traditional" in nature for a financially stable going concern.

As part of the process of emerging from bankruptcy, the debtor (NWE) must prepare a Disclosure Statement and Plan of Reorganization (POR) for consideration by its creditors. The POR is a very specific plan for meeting the needs of creditors, and includes forecasts of the company's operations for the next five years to show the potential financial outcomes of the reorganization plan. Because NWE's representations to its creditors in bankruptcy are critical to the company's planned emergence, the effect of these plans on utility operations is germane to future utility reliability.

NWE made the following assumptions regarding capital expenditures in its 2004-2008 financial forecast:

> *Capital expenditures are budgeted to increase in 2004 to $77 million (consolidated) in part due to certain planned system maintenance and upgrade projects. Thereafter, (2005-2008) capital expenditures are projected to range between $71 and $73 million (annually).*

According to the company, as well as analysis above, the 2004 capital budget includes several major projects and "catch-up" expenditures that it had to defer in 2003. The company identified these higher expenditure levels as being required in the 2004 budgeting process. On the other hand, the company did not prepare the capital spending levels forecast for 2005-2008 with a detailed, bottom-up planning process. According to company executives, the 2005-2008 capital forecast includes organic growth and system maintenance expenditures, but does not include any major system upgrades that may be required, nor does it include estimates of special capital projects such as extensions to major new customers. The forecast also does not include a rate increase in these years, which the company would probably need to support major capital projects. While the company has factored major capital projects into the 2004 plan, it has not yet prepared a capital forecast with all expected utility capital expenditures for 2005-2008.

7. Findings and Recommendations

NWE–M's T&D capital expenditures decreased significantly in 2002 and 2003 from levels experienced in the late 1990s. Capital spending reductions from budgeted levels in 2003 affected priority 5 areas most significantly, including fleet purchases, facilities printing services and general office, information services capital expenditures, electric and gas distribution blanket work, electric transmission 100 kV rebuild work, and Ovando switchyard planned work. Capital spending reductions in 2003 were somewhat disproportional in that utility maintenance was the primary area reduced.

After adjusting for changes in capital accounting and the end of DSM expenditures in 1999, comparisons of annual spending levels show a fairly steady decline since 1996. T&D capital spending declined from $76.6 million in 1996 to $61.2 million, $54.4 million, and $49.1 million in the succeeding three years. Following a rise in capital spending to $53.8 million in 2001, the company cut T&D capital spending in 2002 and 2003 to $45.3 million and $45.0 million, respectively. The 2002/2003 capital spending levels represent reductions of over 34 percent from total 1996/1997 levels, and over 22 percent when the impact of major projects is removed. The 2002/2003 capital levels were also 16 percent below 2001 levels. These comparisons do not factor inflation or system growth into the comparison, both of which would have the affect of making the reductions larger. Productivity and efficiency improvements would have an offsetting effect in its influence on expenditure levels.

The company cut NWE–M maintenance capital expenditures because of NWE's financial problems in 2003. Priority 5, System Integrity Critical, was especially hard hit. The original budget request for this maintenance category was for $19.1 million. The company cut this request to $11.8 million in the budgeting process through a careful prioritization of these maintenance projects to meet the targeted spending cap. Reductions in budgeted spending during the year due to cash constraints caused actual spending in the priority 5 category to only total $4.2 million of the $11.8 million budgeted. Overall, maintenance capital spending in priorities 1-5 were 26.3 percent below the constrained levels included in the 2003 budget.

Capital spending has also been constrained over the past several years by the concept of aligning such spending with depreciation levels. The long-term application of such constraints could negatively affect the reliability of the Montana electric and gas systems.

Montana Power's and later NWE's planning concept of limiting capital expenditures to depreciation levels is one that is based on financial considerations, usually in conjunction with frozen or declining rates. Where utility rates are frozen, which numerous jurisdictions experience as a result of restructuring settlements, there is clearly a financial incentive to limit capital expenditures to depreciation levels, and to limit operating expenses to the levels included in rates. Such spending discipline gives the utility a chance to earn its authorized rate of return, or even more. Such discipline is not necessarily consistent with maintaining system reliability, however, especially if spending is constrained for several years.

The levels of depreciation at a utility are determined by applying a weighted average depreciation rate to groupings of utility plant and equipment. Depreciation rates are determined in periodic studies of the useful lives of utility capitalized assets. The weighted average depreciation rate for a utility times its gross plant in service results in an annual depreciation expense charge that is a reasonable estimate of the cost of capitalized assets for that year. While depreciation is a well-established accounting principle for charging ownership costs over the lives of assets, and for establishing rates based on historical costs, it is not designed to estimate replacement capital required.

The reason that depreciation is not representative of utility capital replacement costs is because a utility's gross plant in service is an amalgam of assets purchased at various points in time during the past 50 or more years. The cost of the assets purchased has changed over this time, as well as technology and the size of the utility system. A simple example of depreciation versus replacement cost can be made with utility poles, a staple of the business. If one assumes that utility poles have a consistent useful life of 40 years, gross utility plant could include some poles purchased 35 years ago for $50, some poles purchased 20 years ago for $100, and some poles purchased last year for $250. Annual depreciation on poles is calculated on a pool of poles with an average cost of $120, making the depreciation expense for poles less than half of the replacement cost. Obviously, the level of depreciation does not equate to capital replacement dollars if inflation is considered.

In addition to inflation, depreciation levels do not take into account future growth in the system, changes in technology, increasing customer expectations, or productivity improvements. Spending at depreciation levels may make sense from a financial and rate standpoint, but not from an operational or reliability point of view.

The company provided capital additions to plant in service and annual depreciation for Montana T&D, gas and electric, for 1996 through 2003. Capital additions are a rough approximation of capital spending; construction work in progress and delays in recording the assets to plant accounts can cause short-term differences. From 1996 through 2000, T&D capital additions were greater than depreciation by large amounts in each year. From 1996 through 2000, additions totaled $269.2 million, while depreciation totaled $187.8 million. Additions were over 143 percent of depreciation for these four years.

In each of the years 2001-2003, capital additions were less than depreciation, when adjusted for the 2003 capital addition of a formerly leased AMR system in use since the late 1990s. Additions totaled $125.8 million for these three years, as compared to depreciation of $135.6 million. Looking forward, 2004 capital spending is budgeted at $51.3 million; 2003 depreciation was $46.6 million. The company currently targets 2005-2008 capital expenditures at depreciation levels.

Capital spending reductions and limitations may affect the ability of NWE–M to provide reliable service. The company has significantly reduced capital spending levels for T&D during the past several years. The difficult year, 2003, saw reductions in budgeted system maintenance expenditures. And, although the company considers 2004 to be a "catch-up" year for capital spending, a critical reliability project backlog may be building.

Although significantly more dollars are budgeted for system maintenance and reliability projects in 2004, the spending increases are concentrated in priorities 2, 3, and 4. The priority 5 maintenance budget is only $8.0 million, or $3.8 million less than in 2003. This shift in maintenance dollars to higher priority categories may indicate that projects in the budget are becoming more critical on average, if priority ranking is consistent from year-to-year. It also means that the company plans a smaller portion of the System Integrity Critical requests for 2004 than in 2003, potentially adding to the backlog of critical reliability projects. Priority categories 6-9 received no funding in either 2003 or 2004.

For 2005-2008, the company's current forecasts do not include capital spending estimates for either major system upgrades or special projects such as large new customer extensions. For example, the Three Rivers/ Jackrabbit electric transmission project is budgeted for $5.4 million in 2004, out of a total project budget of $13-$14 million. NWE–M has scheduled the project to continue in 2005 and 2006. However, additional project-related spending for these years is not specifically included in the company's current financial forecasts.

The levels of capital expenditures in the company's current 2005-2008 forecasts may also be causing a backlog of critical reliability projects. The company's forecast shows Montana T&D capital expenditures for 2005-2008 at around $48 million per year. Based on the budgets for 2003 and 2004, this level of expenditure would fund only a portion of the priority 5 projects, and none of priorities 6-9, in the next 4½ years. This high-level assessment indicates that a backlog of critical projects could be building. However, a more detailed study would be required to determine if such is the case.

Refer to the recommendation at the end of the operating expenses section below.

C. Operating Expenses

1. 1996-2004 Operating Expenses

The table below presents a high-level summary of NWE–M's electric and gas operating expenses and budget for 2004. The total electric and total gas rows do not include the pension portion of A&G expenses.

Montana O&M Expenses, 1996-2003 Actuals and 2004 Budget ($ millions)

Electric	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Transmission	9.5	10.2	15.1	14.5	14.9	10.3	14.3	12.8	13.1
Distribution	20.4	21.4	24.7	24.1	23.1	22.1	18.8	21.7	24.3
Total T&D	30.0	31.5	39.8	38.6	38.0	32.4	33.1	34.6	37.4
Customer Service	11.3	11.7	11.3	13.2	9.9	10.8	10.7	11.2	11.3
A&G	43.7	43.9	35.4	47.0	42.4	46.4	44.0	32.9	45.4
Total Electric (no A&G pension)	71.1	76.4	92.5	101.8	90.0	87.7	82.7	76.7	94.1
Gas									
Trans. & Storage	4.7	4.4	7.2	7.1	8.0	7.3	7.2	7.4	7.0
Distribution	7.5	7.6	9.5	8.7	7.9	7.6	6.6	7.6	7.9
Total T&D	12.2	12.0	16.8	15.9	15.9	14.9	13.8	15.0	14.9
Customer Service	3.8	5.2	5.1	5.1	4.8	5.7	4.5	4.6	4.7
A&G	15.3	14.3	12.4	14.0	15.6	17.8	17.4	13.5	18.7
Total Gas (no A&G pension)	26.5	27.7	34.9	35.3	36.2	37.3	34.0	31.7	38.3

A review of NWE–M's operating and maintenance expenses showed:

- Transmission supervision and engineering expenses have declined about 33 percent between 1999 and the 2002-2003 timeframe. Two separate early retirement offerings and changes in benefit loadings drove these reductions.

- Electric transmission overhead line expenses declined sharply during the company's 2002-2003 financial problems. The 2002-2003 levels of spending were almost 38 percent lower than 1999 levels. The company noted that it reduced proactive spending in this activity in 2002 and 2003 due to cash constraints. Reductions included lower contractor costs associated with inspections, overhead line clearance, test and treat inspections, and pole maintenance, as well as lower switching and line outage costs. The 2004 budget includes an increase of 78 percent over the 2002-2003 spending levels, including greatly increased proactive spending.

- Electric distribution supervision and engineering decreased sharply in 2000 and 2002. The decrease in 2000 was primarily due to an early retirement offering, which caused a reduction in field division headcount by about 50. A significantly increased miscellaneous distribution account offset this reduction. This account increased nearly $3 million between 2000 and 2002 due to flextime moving from supervision and engineering in 2000 to miscellaneous distribution in 2002.

- Electric distribution overhead lines operation and maintenance expenses decreased sharply in 2001, 2002, and 2003 from peak levels in 2000. The average of the spending in these accounts in 2002 and 2003 was less than 50 percent of the 2000 level. The company reported a reduction in proactive spending in 2002 and 2003 due to cash constraints, with lower outside contractor outlays associated with inspection and switching. Fires and fire restrictions and reduced line outages also caused lower spending. The 2004 plan includes a 56 percent increase above the 2002/2003 levels.

- Gas transmission mains expenses decreased almost 30 percent in 2002-2003 from levels in 1998 and 1999. Most of the dollar decrease is in the account used for lowering and changing the location of lines, installing and removing temporary lines, supervision, and leak inspections. The company notes a decrease in location changes and removals of existing pipe in recent years. Even lower spending is budgeted for 2004.

- Most of the increase in administrative and general spending in the 2004 plan is attributable to electric and gas insurance accruals, which increase from only $0.5 million in 2003 to $10.7 million in the 2004 plan. Increased D&O (directors and officers) insurance costs caused the large increase in 2004 due to the risk associated with bankruptcy and pending legal suits. The company also advises that these insurance costs should decline after the company emerges from bankruptcy.

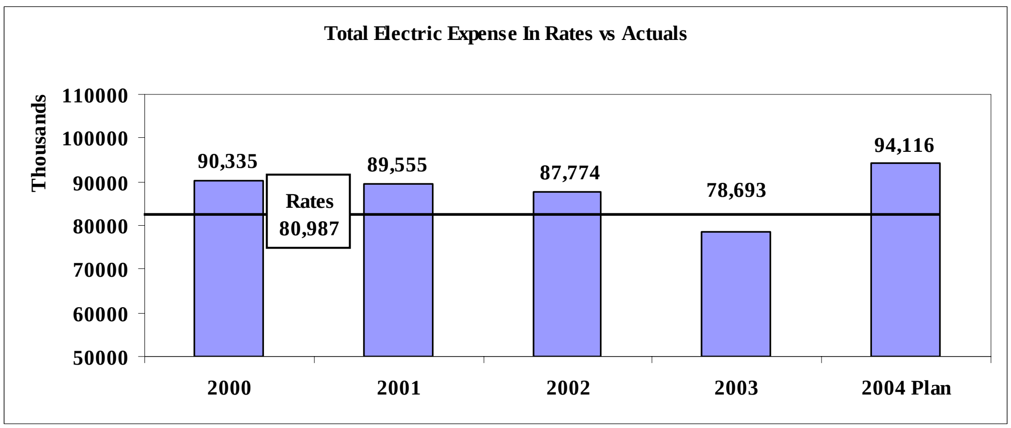
2. Strategic Planning Influences

Montana Power Company's business plans for the years 1998-2002 indicated a consistent theme of attempting to reduce the budget year O&M and A&G expenses from the previous year, although by small percentages. For instance, the 1999 business plan included utility operating expenses that were $4.4 million less than the 1998 budget level. The 2000 business plan included

2000 expense levels that the company targeted at a 4 percent reduction from prior levels for each area of the utility unit. However, drastic reductions in operating expenses were not a major theme in strategic planning from 1998-2002. Rather, the company expected incremental efficiency improvements to reduce the rate of increases to less than the inflation rate. The business plans consistently stated the company's intent to target the increase in operating expenses in years 2-5 of the five-year plans to less than the rate of inflation, which it assumed to be about 2.5 percent annually.

3. Rate Case Spending Levels

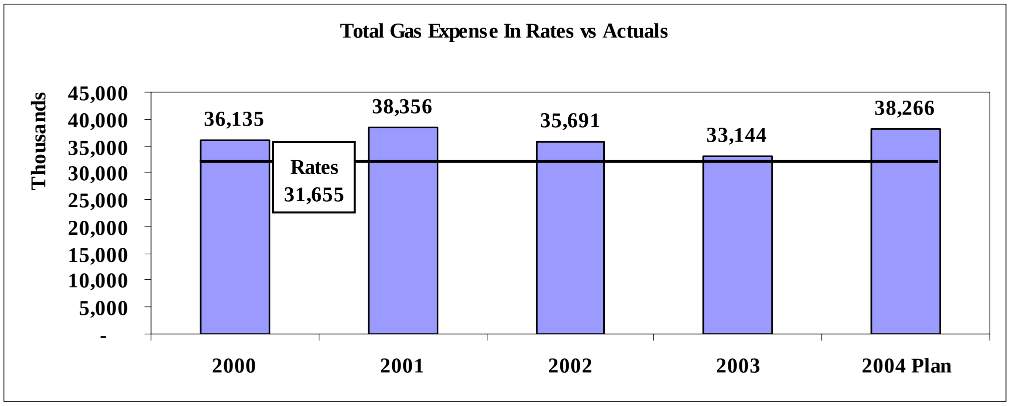
The PSC established new rates for both the Montana electric and gas businesses in late 2000 on the basis of a 1999 test year. The levels of authorized operating expenses included in the ratemaking revenue requirement are important cost management measurements for utility management. Expense levels significantly above the levels included in rates will cause utility earnings to be below authorized rates of return. The chart below shows the level of electric operating expenses included in rates and the actual dollars spent in 2000-2003 and as budgeted in the 2004 plan.



Montana electric operations have spent significantly above the expense levels included in rates since new rates became effective in 2000, with the exception of the spending-restricted year of 2003. The 2000 electric operating expense levels were 11.5 percent above the levels in rates, and the 2004 plan calls for operating expenses that are 16.2 percent above rate levels.

While electric operating expenses overall have been above the levels in rates, this general observation does not tell the whole story. Electric administrative and general expenses were $47.0 million in 1999, but only $34.7 was included in rates based on a 1999 test year. A&G spending stayed at levels well above rate levels until 2003 reductions, and the company expects them to return to near-peak levels in 2004. However, most of the 2004 planned increase in electric A&G spending is attributable to D&O insurance increases of over $7 million.

The chart below shows similar comparisons of operating expense levels to rate levels for the Montana gas business.



Gas operating expenses have also been well above the levels included in current rates. Gas operating spending exceeded the levels in rates by 21.2 percent in 2001, and the company expects it to be 20.9 percent above the levels in rates in 2004. The primary cause has been gas A&G expenses that rose far above rate levels before major reductions in 2002 and 2003. A&G spending will rise to peak levels in 2004, due primarily to D&O insurance increases of over $3 million.

4. Future Considerations

NWE-M's spending on operating expenses will be constrained by the company's planned emergence from bankruptcy. The NWE financial forecast includes the following statements regarding consolidated operating expenses for 2004-2008:

> *Operation and maintenance expenses (excluding pension expense) are forecasted to be relatively constant in 2004 versus 2003 and are projected to grow at 1.0% to 1.3% thereafter to reflect the corresponding growth in revenues and load growth described above. General and administrative expense is projected to decline 3% or $1.5 million from 2003 to 2004 and 8% or approximately $6.5 million from 2004 to 2005 due to reductions in insurance costs and benefits from other administrative efficiencies. G&A expense is projected to decline approximately 3% on a yearly basis thereafter. On a combined basis, O&M and G&A expenses increase by less than $3 million from 2005 to 2008.*

Liberty notes that NWE–M's 2004 T&D budget for O&M is 5.5 percent higher than 2003, not flat.

As of December 31, 2003, the NWE pension funds were under-funded by an estimated $128 million. The following passage from the POR describes the scheme for funding this shortfall:

> *Pension funding is projected to be approximately $10 million in 2004 and $19 million for (each of) the years 2005 through 2008, respectively. Substantially all of this funding is associated with the projected underfunding in the Montana pension plan.*

The company's projected annual operating expenses for 2004-2008 are effectively level. As a result, the forecast includes minimal assumed changes in total utility operating expenses from levels experienced in 2003.

5. Findings and Recommendations

Operating expenses for the Montana T&D operations have experienced above-average variability for a utility delivery operation during the past several years. Spending levels grew at high rates until about 1999, and then decreased slightly for two years before falling steeply in 2002 and 2003. Montana Power, as indicated in its business plans, instituted small reductions in operating expense budgets starting in 1999 and 2000, and planned for following years to increase by less than the rate of inflation. The following are other major changes that had significant influences on utility operating expenses:

- A restructuring agreement which included the sale of the electric generation business in 2000, causing a reorganization of staffing.
- Early retirement programs in 2000 and 2002 that reduced both the T&D field staff and various support staff levels.
- Universal system benefits expenses that increased A&G expenses by $9-$10 million annually, starting in 1999.
- The installation of new financial software and related consulting that increased A&G expenses in the 1999/2000 period.

In 2002 and 2003, NWE–M experienced significantly reduced spending levels on operating expenses, related mostly to the weakened financial condition and insufficient liquidity of NWE. The operating spending decreases were concentrated in the following areas in 2002 and 2003:

- Transmission supervision and engineering
- Transmission overhead lines
- Distribution supervision and engineering
- Distribution overhead lines
- Gas transmission mains
- Administrative and general salaries.

In its 2004 plan, the company restored previous spending levels for transmission overhead lines, distribution supervision and engineering, and distribution overhead lines. A&G salaries include a moderate increase for 2004. Transmission supervision and gas transmission mains remain at reduced levels in the 2004 plan.

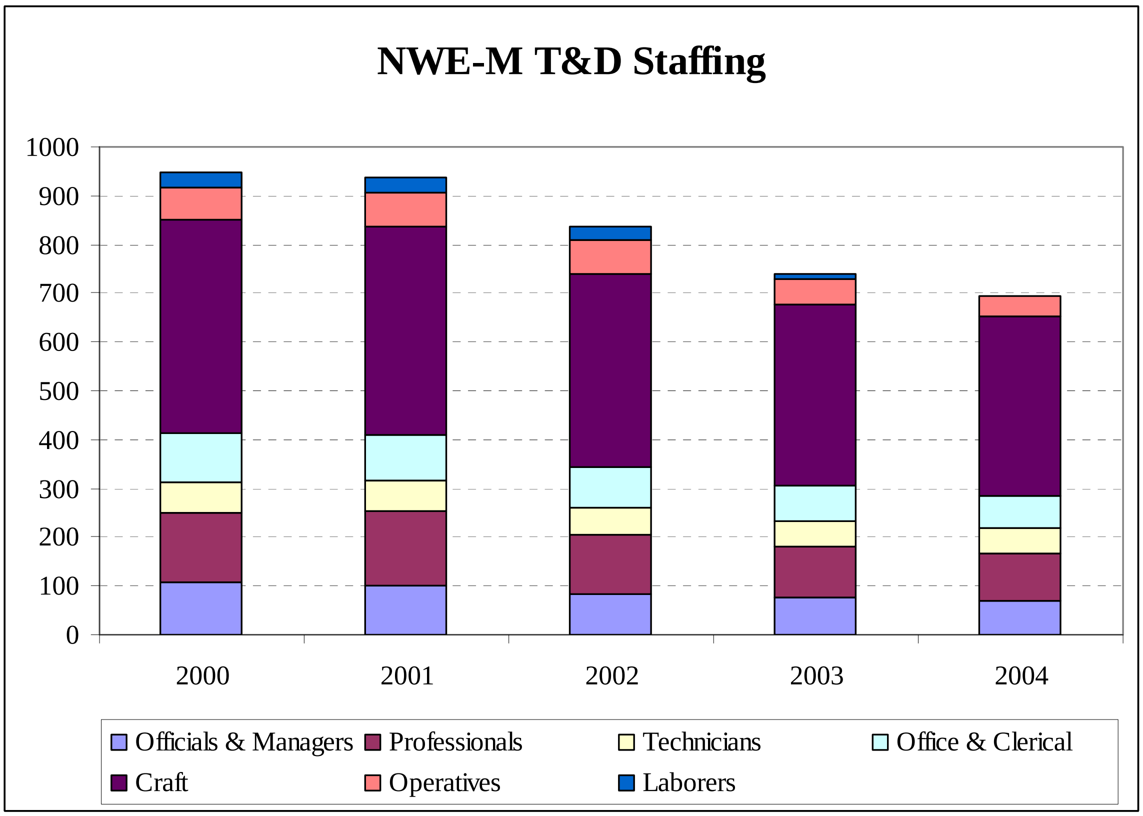
Large increases in two expense categories in 2004 and later that are unrelated to utility service could burden T&D operations. The unfunded pension liability of $128 million is large for a company of this size, and will require funding of about $20 million per year. NWE's financial difficulties have also caused an increase in D&O insurance charged to Montana T&D operations of over $10 million in 2004. A portion of this increase will probably remain for the next few years. These two large operating expense increases may have an effect on future utility spending levels. With current rate levels, the company cannot afford higher levels of operating expenses that are not included in rates. If the company holds Montana T&D total operating expenses near 2003 levels, the increases in pension funding and D&O insurance would squeeze utility field spending. As a result, increases in field spending in 2004 could be temporary unless the company plans for additional funding to maintain the increases.

Recommendation V-1:Financial Forecast

Liberty recommends that the company prepare bottom-up financial forecasts for 2005-2008 that include all projects that will be required to maintain system reliability, including all major upgrade and required special projects, and that include operating and maintenance expenses necessary to maintain reliability and operational goals. NWE should factor the levels of total capital and O&M expenditures from the revised forecast into its financial planning.

D. Staffing

NWE–M's T&D staffing decreased from 950 in year 2000 to 695 in year 2004, a 27 percent drop. The largest year-to-year decrease was from 2002 to 2003 when T&D staffing dropped by 11.5 percent. The chart below shows annual T&D staffing by EEO category.



The largest percentage decrease among the EEO categories was Operatives, which dropped from 66 people in 2000 to 41 in year 2004. These are personnel located in the divisions, classified as semi-skilled, and having jobs in areas like construction, administration, and warehousing. The EEO category "Officials & Managers" decreased by 37 percent from year 2000 to 2004. Locating managerial positions in NWE's South Dakota headquarters may explain some of this decrease. Skilled craft personnel had the smallest percentage decrease, dropping from 437 in year 2000 to 366 in 2004, 16 percent.

With respect to providing reliable and timely T&D service, the most significant personnel decrease may be the drop in professionals and technicians. The total of these two categories dropped from 205 in year 2000 to 150 in 2004, a 27 percent decrease. This category includes the engineers who design new connections, system reinforcements, and system integrity projects. Insufficient numbers of these personnel could lead to delayed work or engineering work that is not accurate or correct. While NWE–M has completed a staffing study of its distribution field personnel, it has not examined whether the current number of engineers and technicians is sufficient to provide reliable, safe, and quality service.

Recommendation V-2: Staffing Evaluation

NWE–M should conduct an assessment of professional and technician staffing to determine the optimum manpower levels necessary to meet its T&D safety, reliability, and operational objectives.

E. Benchmarking and Cost Indicators

1. Background and Analysis

NWE regularly tracks, compiles, and analyzes cost indicators for its electric and gas delivery operations. The process begins with the benchmarking of key performance measures against those of other utilities. NWE has used PA Consulting to provide benchmarking compilation and analysis. It also uses information from the Edison Electric Institute, the American Gas Association, the Electric Utility Cost Group, and the American Productivity and Quality Center. The company's benchmarking efforts focus on cost, reliability, and safety performance measures. The cost benchmarking uses various expense per customer, expense per circuit mile, and expense per MWH measures for the NWE utility entities (Montana, South Dakota and Nebraska), as compared to other participating utilities in PA Consulting's database.

PA Consulting's NWE benchmarking presentation for 2003 included 2002 data. NWE has recently been submitting annual data from 2003 to PA Consulting, along with the company's FERC Form 1, for the 2004 benchmarking study.

Liberty reviewed the high-level benchmarking reports prepared by PA Consulting. The reports provide the results for cost, reliability, and safety key performance indicators for NWE's individual utility operations in Montana, South Dakota and Nebraska. The reports compare these performance indicators to the mean of indicators from other utilities, and slot NWE's performance in a quartile ranking. PA Consulting uses about 30 utilities in its cost database. The company recognizes that most utilities in the database are not comparable to the Montana operations due to the unique geographic, customer density, and rural nature of the Montana service territory. The Montana T&D operations serve one of the lowest density service territories among U.S. utilities. The territory includes large portions that are in mountainous areas. The company notes that only five or six utilities are comparable to the Montana operations due to these unique characteristics.

The company uses the high-level industry performance comparisons to identify areas where the company is either significantly better or worse than other utilities in the database. Recognizing that the company's geographic and demographic characteristics are different than most in the database, the company must perform more analysis to determine the reasons for any large differences. The company indicated that it looks at outlying performance areas more closely and sometimes makes comparisons to a subset of utilities that are more comparable.

In the 2003 benchmarking study, the high-level analysis indicated that the following were strong key performance measures (first quartile) for the Montana operations as compared to the industry group:

- Transmission capital additions and O&M per circuit mile
- Substation expenditures per customer
- Substation expenditures, capital additions and O&M per breaker and per book value
- Distribution outages per 100 circuit miles
- Distribution CAIDI without major events
- T&D SAIFI without major events
- T&D vehicle accident rate.

The study showed the following Montana areas as having negative performance (fourth quartile) in the 2003 benchmarking study:

- Transmission line O&M expense per customer and MWh transmitted
- Transmission line capital expenditures per MWh transmitted
- Transmission sustained forced outage events per 100 circuit miles
- Transmission momentary forced outage events
- Transmission line availability
- T&D lost time incident rate.

The company flags the poorer performance areas (third or fourth quartile) as areas or processes that may need improvement. After additional comparisons and information gathering to determine whether the company actually needs improvement, personnel may make specific recommendations for the company's process improvement program. The company's process improvement initiatives are inputs to the company's goal setting process for the following year's budget.

The asset management team manages the company's process improvement initiatives. It prioritizes and recommends initiatives to the company's senior management, with cost efficiency as one of the highest decision inputs. Senior management decides which initiatives to implement. Asset management then forms teams for each initiative and manages the process. The following were prioritized process improvement initiatives for 2003:

- Implement Building Trust Between Union and Management
- Implement Work Force Planning – Productivity/Planning
- Evaluate Streamlining New Construction Process
- Consolidate Safety and Environmental Programs for MT/SD/NE
- Implement Process Improvement Tools
- Evaluate Job Site Reporting, Work Shifts, Work Rules
- Evaluate Energy Entity Key Measures/Scorecard
- Implement Line Clearance Policy
- Evaluate Integration of SD Dispatch into MT
- Implement Utilizing Gas Transmission Crews Across the Company
- Evaluate Improving Budget Process
- Evaluate Unregulated Activities
- Evaluate Centralized Drafting/Mapping
- Evaluate Security Needs.

2. Findings and Recommendations

The company has an effective process in place that uses high-level cost indicators to identify potential problem areas or areas that need improvement. Using this high-level information tends to be difficult because of the unique nature of the Montana service territory, making comparisons to the overall U.S. industry group less meaningful. However, the company recognizes these differences and focuses on a more comparable group of companies in interpreting the results. The follow-through of the process improvement initiatives also seems reasonable and effective upon brief review.

While these programs undoubtedly improve the effectiveness and cost efficiency of the Montana operations over time, they have little effect on reliability or reliability spending. The company uses these programs primarily to improve efficiency.

Comparisons between companies of costs per mile or customer are not revealing regarding reliability. Spending on reliability for Montana T&D is very specific to the needs of the Montana system, which is like no other. Changes in levels of expenditures on the Montana system, however, may have an effect on reliability levels over time. Reliability impacts from changes in spending levels and activities are on a significantly lagged basis. A company may not realize the effect of increases or decreases in the spending on maintenance activities on its system until years later. As a result, the most useful cost indicators for a utility are changes in its own cost measures over time. This information may be compared to changes in the company's own reliability measures to determine the cause-and-effect relationship between changes in expenditure levels and trailing reliability measures.

The PA Consulting report also included information on "Asset Management" measures that are particularly relevant to the NWE–M situation. PA Consulting calculated the "T&D Net Assets Replacement Rate" for the individual NWE utilities and other companies in the database. The capital additions of a company less new business additions, divided by depreciated assets, results in an asset replacement rate. Montana's 2002 rate was between 4 and 5 percent, one of the lower rates on the chart. One of the assumptions in the analysis is that "replacement cost is twice initial installation cost."

The PA Consulting report also provides a revealing replacement capital chart, which calculated the percentage of capital additions less new business additions, divided by current year depreciation. For 2002, the Montana T&D's replacement percentage was only around 70 percent, again one of the lowest on the chart. The utility mean was 192 percent. That is, the utilities in PA Consulting's database spend on average replacement capital at about twice depreciation. This fact supports a conclusion that capital spending on the NWE–M T&D system at 2002 and 2003 levels is insufficient to maintain long-term reliability.